

# SAN FRANCISCO LOCAL AGENCY FORMATION COMMISSION ENERGY SERVICES STUDY

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# EXECUTIVE SUMMARY

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This draft of the San Francisco Local Agency Formation Commission (SF LAFCo or the Commission) Energy Services Study (the Study) is a continuing work in progress, and is provided for discussion purposes and comment. It is expected that revisions, additions, and possibly deletions will take place before the Study is finalized on or about July 1, 2002.

## Report Purpose and Industry Structure

### Purpose

Since electric industry restructuring was first implemented in 1998, residents and businesses in San Francisco have witnessed or been affected by opportunities to participate in customer choice (Direct Access), the bankruptcy of the Pacific Gas and Electric Company (PG&E), wholesale electricity price volatility, retail electricity tariff increases, and unprecedented rotating blackouts. This report has been prepared to support the development and evaluation of options available to San Francisco to better manage three key elements of electricity service:

- Rates and Pricing
- Reliability (shortages and outages)
- Local Control

This report focuses on options available to San Francisco in regard to business roles and methods of service delivery that could have a material impact on the three elements listed above. The report is primarily qualitative rather than quantitative. A quantitative evaluation cannot commence until policy options have been agreed to, scenarios and financial assumptions developed, and preliminary or prefeasibility analyses undertaken.

The report contains sections that address the following electric services and issues:

- Wholesale Power Market Costs and Risks
- Transmission Issues
- Electric Energy and Distribution Service Issues and Options
- Conservation, Energy Efficiency, and Renewable Resources

Readers should understand that, even though the restructured electric industry has been unbundled in much the same way, there is significant linkage between these business components. As an example, the addition of new transmission can reduce the need for local generation, and aggressive conservation and energy efficiency programs can offset the need for transmission, generation, and distribution facilities.

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The services and issues are reviewed in relation to their impact on rates and pricing, reliability, and local control. Governance and ownership options are also discussed and presented in terms of three alternative service providers:

1. PG&E
2. San Francisco Public Utilities Commission (SFPUC)
3. A new San Francisco Municipal Utility

Where practical the authors have looked at the effects on price, reliability, and local control for each service provider option. This will be particularly evident in sections on transmission, distribution, and conservation and energy efficiency.

## Industry Structure

The full report provides a high-level view of the changes that have taken place since California began the process of restructuring the electric industry. That outline of how we got to where we are is useful, but not critical to the choices that San Francisco is considering. What is critical is an understanding of outstanding legislative and regulatory issues, the progress of new power supply resource additions (particularly in and around San Francisco) and the uncertainties that decision-makers will face as they consider policy alternatives. Important activities to follow include:

- PG&E is in bankruptcy. Two competing plans have been approved by a creditors committee that will be considered by the bankruptcy judge. Each would have very different outcomes with regard to PG&E's business structure, regulatory jurisdiction, and electricity tariffs.
- The Federal Energy Regulatory Commission (FERC) is considering issues such as rebates from generators and marketers for excessive power supply costs in 2000 and 2001; market restructuring to mitigate market gaming; transmission ownership, operation, and control; and price cap extensions. Decisions on each of these issues will affect the options available to San Francisco, including the Status Quo option. All three of the key elements of service will change as a result of FERC rulings.
- The California Public Utilities Commission (CPUC) and the California Legislature are considering ways to reinstate Direct Access. Decisions will affect the types of service delivery available for San Francisco's consideration, as well as the exit fees or non-bypassable charges that could effectively financially block the implementation of these choices.

As these issues are resolved and more certainty in industry structure develops, stakeholders will make choices on investment in generation and transmission; electricity customers will be able to better evaluate their choices to invest in conservation, energy efficiency, demand management, renewable, and Distributed Generation; and new entities will evolve to take advantage of new market opportunities.

It has been eight years since California began to consider electric industry restructuring. Implementation has resulted in electricity cost penalties that will persist for the next 10 to 15 years. San Francisco policy-makers will be deliberating during a

period of regulatory and legislative uncertainty, electricity price instability, periods of compromised reliability, and rapid industry evolution.

## **Power Supply**

Since the federal government encouraged competition in wholesale power markets through the Energy Policy Act of 1992, there has been a proliferation of new players (Independent Power Producers and Energy Merchants) in wholesale power markets. Independent Power Producers are building power plants and offering the power to load. Energy Merchants buy the rights to output of power plants and resell power. These players also provide numerous physical and financial options to load serving entities to for purposes of ensuring reliability and hedging risks. Transmission access rules are also going through major overhaul as FERC attempts to ensure that there is optimum ability for competing supplies to reach electric loads.

## **Last Year's Problem**

Following deregulation, wholesale power supply prices throughout California, although somewhat volatile, remained within a predictable range until May 2000. Then a combustion of the following factors caused severe price excursions:

- During the decade of the 1990s, growth was occurring and generating reserve margins were declining.
- Above-average hydro conditions masked the effect and kept prices somewhat depressed.
- Developers were reluctant to pursue new projects due to these economics and the difficulties in permitting new generation projects.
- PG&E and other Investor-Owned Utilities (IOUs) were, for a variety of reasons, highly dependent on short-term spot-market energy purchases.
- Retail rates were frozen and not linked to wholesale energy prices, effectively discouraging any demand response to price increases.
- Hydroelectric generation in the West declined markedly in the summer of 2000.
- Natural gas storage was low and a major pipeline into California failed just as the demand for gas to fuel thermal power plants escalated.
- Natural gas costs make up a predominant share of the cost of units that were required to meet margins on the peak. This drove up generating costs.
- Energy traders may have been manipulating gas and electricity markets, exacerbating the situation.
- Soft price caps were not effective in controlling price excursions

## **Near-Term Outlook**

Today's outlook for wholesale power prices in the next few years is more positive. Wholesale power prices have been moderate, if not depressed during the past year.

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This price downturn is the result of the concurrent economic downturn, retail rate increase price elasticity, consumer conservation combining to reduce loads, return to normal hydro conditions, and the completion of new generating plants to increase supply. Regulatory response to charges of market manipulation, including the short-term continuation of price caps, should help moderate prices as well.

The conclusion is that:

- Wholesale prices are likely to remain stable and slightly depressed throughout the Western Electricity Coordinating Council (WECC) region.
- Comfortable reserve margins will be maintained for the foreseeable future.
- Considerable uncertainties will persist.

## Long-Term Outlook

Key regulatory issues of specific concern to San Francisco include:

- The potential imposition of Location Marginal Pricing, which could increase costs due to transmission constraints and the fact that local generation is insufficient to meet local demand.
- Environmental risks associated with local gas-fired generation.
- Technological change, such as more efficient new generation, expanded use of Distributed Generation, and electricity storage.

In the WECC region, power supply and demand balance is predicted until about 2009. In San Francisco, by 2003, supply from local generation (650 MW) is expected to meet only two thirds of the estimated 960 MW of demand at the best of times assuming all generation is available. Any deficiencies will have to be imported over limited transmission into the Bay Area and the City of San Francisco. Reserve margins are predicted to be -32.3% in 2003 and to worsen to -44.4% by 2012.

## Wholesale Generation Market Risk Factors

To the extent that a SF Muni takes on any obligation for energy supply, whether through some form of aggregation or distribution service, it will need to consider several risk factors:

- Integrated planning will be required to balance power supply commitments and loads.
- Volatility and market uncertainties will carry very significant risks.
- Forward contracting will be essential.
- Long-term risks will affect the economic viability of market participants. Relevant risks are demand uncertainty (including loss of customers), supply risk, fuel price risk, market regulatory uncertainty, environmental regulatory uncertainty, and technological change.

- Short-term market price fluctuations will be driven by weather, seasonal hydroelectric potential, fuel price, generating equipment outages, and transmission availability.

Developing a portfolio of electricity supply sources for a load that fluctuates hourly, daily, monthly, and annually is a complicated undertaking. Only through a detailed Integrated Resource Plan (which adequately addresses load and power supply risks) will it be possible to identify an appropriate portfolio of supplies and determine the cost of the commodity to consumers. While this report is primarily qualitative, an effort has been made to provide a rough estimate of generation costs that might be experienced in meeting loads in the San Francisco peninsula area. The three scenarios analyzed and rough costs are:

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| Electricity Supply Source                   | Approximate<br>Cents per kWh |
|---------------------------------------------|------------------------------|
| (1) 100% Purchases From Spot Markets        | 3.9¢                         |
| (2) 50% Long-Term Contract, 50% Spot Market | 4.1¢                         |
| (3) PG&E Tariff (Utility Generation + CDWR) | 5.7¢                         |

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The numbers presented above do not reflect “exit fee” ramifications. The CPUC is in the midst of the process of determining exit fees for direct access customers. The outcome of such proceeding can impact the cost under each of the three scenarios. In order for a SF Muni to evaluate any role in power generation or contracting, it would be necessary to add exit fees to Scenarios 1 and 2, and to update CDWR and other exit fees in Scenario 3.

## Options for San Francisco

Options for San Francisco include:

- Continue to rely on PG&E and CAISO to effectively address transmission constraints, offsetting the need for local generation.
- Continue to invest in and to escalate programs for renewable and distributed resources in San Francisco.
- Rely on developers to replace and expand insufficient and unreliable power plants with new technology-efficient and low-emission generation.
- Invest through a SF Muni in transmission upgrades into San Francisco.
  - Create a Control Area and retain operational control.
  - Invest in and turn transmission upgrades over to CAISO to enhance revenue recovery.
- Invest through a SF Muni in new generation at the airport or other appropriate sites. Revenues can be recovered using a variety of mechanisms, such as:
  - Sell into the market.

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- Bilateral contracts.
- Retail sales through aggregation of fully integrated distribution.
- Supplement and firm up Hetch Hetchy supplies; sell balance.

## Transmission Issues and Options

The existing transmission into San Francisco is planned according to standards that are equal to or higher than those used elsewhere in California. Unfortunately, electric consumers in the city continue to obtain less reliable transmission service than other parts of the state due to continued reliance on old, unreliable and emission-limited generation at the Hunter's Point and Potrero Power Plants.

PG&E is planning on building new transmission into and within the Bay Area. If completed, this will tend to increase reliability and reduce costs to San Francisco customers. Cost reductions would take place under current regulations that spread the costs of transmission additions over a large service area, whereas avoided congestion charges are proposed to be recovered locally. Still, the transmission additions by PG&E are not likely to be sufficient to mitigate San Francisco's potential exposure to congestion charges.

Because of the likelihood of continuing transmission constraints under PG&E, local generation and conservation will be important to improve reliability and reduce exposure to high energy prices for San Francisco. SF Muni-controlled generation within the city would provide similar benefits to new transmission, and potential City investments in generation should be evaluated in an integrated manner that considers the relationship between transmission, generation, conservation, and energy efficiency.

## Opportunities

The City has many opportunities to influence or participate in the creation of an integrated solution to the reducing the cost and improving the reliability of San Francisco power supply. Three of these opportunities are listed below, and each could be pursued either by the SFPUC or by a new municipal entity (municipal utility or municipal utility district).

- The City, through the SFPUC or a new Municipal Entity, could develop new transmission, turn it over to the California Independent System Operator (CAISO) for control, and recover its investment from CAISO payments. This may be the most economic solution.
- The SFPUC or new Municipal Entity could create a separate control area to increase local control, particularly with regard to improving reliability and reducing exposure to rotating blackouts. This solution is likely to be more expensive to San Francisco's electricity consumers than using CAISO-controlled transmission.
- The SFPUC or new Municipal Entity could explore targeted transmission projects that could result in an attractive revenue stream, providing benefits to all City

consumers, as well as to specific customers connected to the SFPUC or new Municipal Entity's transmission facilities.

## **Electric Retail Service Issues and Options**

San Francisco currently receives distribution services from two utilities:

1. Hetch Hetchy Water and Power (HHWP), which is a support bureau of the SFPUC, serves most City loads either with City-owned distribution (such as at the airport) or employing PG&E distribution through an interconnection agreement with PG&E.
2. PG&E provides retail distribution service to the residential and business customers in San Francisco.

The obligation to provide power supply transferred from PG&E to the California Department of Water Resources (CDWR) in January 2000, although a portion of the power supply is provided by generation that is still owned by PG&E and power purchased under contract by PG&E.

## **Service Options**

There are three options that have been considered for supplying retail service in San Francisco. They include two types of aggregation (Facilitator of Aggregation and Aggregator as an ESP), Community Aggregation, and Integrated Distribution Service. Each of these is discussed in the report.

### **Aggregation**

Aggregation can take two forms:

- **Facilitator of Aggregation.** This is the low-risk version where the SFPUC or a new SF Muni would, through their procurement process, select one or more Energy Service Providers (ESPs) and develop standard pricing and service terms that would be available to San Francisco customers. Using the standard terms, customers would contract directly with the ESP such that a SF Muni has no financial risk. This is similar to the business model used by the Association of California Water Agencies for their aggregation program.
- **Aggregator as an ESP.** This is the higher risk approach where the SF Muni would become an ESP. This is similar to the business model adopted by the Association of Bay Area Governments for their aggregation venture. The SF Muni would be responsible for building or contracting for power supply resources, arranging for transmission, scheduling, etc., to meet the load requirements of customers who participate. The SF Muni then takes on the risk of price competition, customer departure, stranded investments, and adequacy of supply. In both approaches, marketing would be required to attract and retain customers in what is expected to become a very competitive market.

Community Aggregation

Community Aggregation is much like the high-risk aggregation model with the risk level lowered by employment of an “Opt-Out” strategy. This means that if a SF Muni became a Community Aggregator, all customers would automatically transfer to SF Muni ESP services unless they opt out. This reduces marketing costs, transfer costs, and greatly enhances the potential for financial success.

Integrated Distribution Services

One of the commonly proposed alternatives to PG&E is the purchase of the distribution system by the SFPUC or a municipal utility, allowing the provision of fully integrated service. The first option available to San Francisco is to maintain status quo, that is, full service from PG&E. This option is compared in the report with two full-service municipalization governance options. The two governance options include either the SFPUC or the formation of a new and independent San Francisco municipal utility. Since in most cases these are only minor differences, these two governance approaches are often combined and discussed as a SF Muni. The following table details the major generic similarities and differences between the PG&E and SF Muni options.

Table ES-1  
Comparison of Distribution Services Between Public Utilities and IOUs

| Service                 | Public/Muni Service                                                                                                                            | PG&E Distribution Service                                                                                                                                                                                           |
|-------------------------|------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Electric Design, O&M    | ■ Similar design standards and construction practices. O&M can depend on budget allocations and be affected by distribution system conditions. |                                                                                                                                                                                                                     |
| Reliability             | ■ Similar standards, both measure SAIFI & SAIDI indexes and attempt to minimize outages.                                                       |                                                                                                                                                                                                                     |
| Safety                  | ■ Both adhere to General Order 95 and 128 standards.                                                                                           |                                                                                                                                                                                                                     |
| Financing               | ■ Financing comes mainly from tax-exempt bonds.                                                                                                | ■ Typically a higher cost of capital that is composed of bonds as well as common and preferred stock.<br>■ Has limited access to tax-exempt debt.<br>■ Financing cost and access can be volatile and unpredictable. |
| Rates/Pricing           | ■ Historical prices have averaged 20% below IOUs for similar customer segments.                                                                | ■ Already have unbundled prices for all customer segments. Usually more pricing options than Muni.                                                                                                                  |
| Taxes                   | ■ Publics are exempt from income taxes, some property taxes, and most franchise fees.                                                          | ■ IOU's pay income taxes, property taxes, and franchise fees.                                                                                                                                                       |
| Regulation              | ■ Self-regulated by an elected governing body.                                                                                                 | ■ Regulated by at least the CPUC and FERC                                                                                                                                                                           |
| Public Purpose Programs | ■ Usually more emphasis on low-income programs, (with community involvement) in mix of public purpose programs.                                | ■ Provides public purpose programs with CPUC oversight                                                                                                                                                              |
| Resource Mix            | ■ Usually have more federal hydro power than IOUs.                                                                                             | ■ IOU's have limited and declining access to federal hydro power.                                                                                                                                                   |

The benefits of public ownership (e.g., SF Muni) have generally been lower rates, historically averaging 20% lower, and the opportunity for local control. Reliability has historically been about equal for public and private ownership.

The biggest risk to municipalization is the likelihood of contested acquisition of the PG&E distribution facilities. Due to geographic circumstances, severance (often a significant part of acquisition costs) would be relatively small for San Francisco.

### **Spot Municipalization**

Spot Municipalization is a subset of Integrated Distribution Services and avoids the need to acquire PG&E distribution facilities. Under this approach a SF Muni would provide distribution services only in redevelopment areas or new developments where new distribution facilities are installed as part of the development. After installation of its required share of the electric infrastructure, the developer would turn the facilities over to the SF Muni instead of PG&E, as is the current practice. Because the SF Muni would not pay income taxes, the developer would save the 34% gift tax they would otherwise have paid to PG&E. From a benefit and risk perspective, this approach is attractive in that it avoids the difficulty of acquiring PG&E facilities and it saves the 34% cost to the developer of deeding facilities to PG&E. However, the costs of operations and maintenance (O&M) will likely be higher, as the SF Muni has to serve non-integrated pockets around San Francisco, reliability may be compromised because of the difficulty of providing alternative or back-up connections to the PG&E distribution grid, interconnection costs with PG&E will add to the cost of service, and different residents and businesses will be provided with different service standards and rate structures.

## **Impact of Alternatives on Key Considerations**

The service delivery options are all somewhat differently impacted with respect to the key considerations, depending on ownership and governance structures. This report addresses these differences for each service option and key considerations.

### **Energy Services Only (Various Forms of Aggregation)**

#### **Aggregation Facilitation, Low-Risk Model**

Aggregation of this type is dependent on reinstatement of Direct Access. A SF Muni would select and negotiate standard pricing and terms with one or more ESPs. The customers would contract directly with the ESP, relieving the SF Muni of supply and cost risk.

- **Rates and Pricing.** One would expect very little difference in rates or pricing from those offered by other competitors. The melding of Hetch Hetchy power is not assumed in this case. The only economic advantage that would be passed on to the customer is a lower marketing cost due to a trust factor that many potential customers may feel towards a public agency, as compared to large energy companies that have, as a group, developed a tarnished image.

## EXECUTIVE SUMMARY

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- **Reliability.** Since PG&E would be providing distribution services, there should be no change in delivery reliability. If rolling blackouts were to return, the fact that PG&E is delivering the power means that SF Muni customers would share the same rolling blackout risks as PG&E full-service customers.
- **Local Control.** There would be local control in the selection process of ESPs and some potential influence on pricing and terms available to retail customers. However, market competition is likely to be the dominant factor in service costs and terms, minimizing the effect of local control.

### Aggregator as an ESP, High-Risk Model

This is also dependent on reinstatement of Direct Access. A SF Muni would become the ESP and have the obligation for sufficient power supply and the risk associated with matching that supply to the aggregated loads (minute by minute). Competitors would include PG&E bundled service and any other aggregator.

- **Rates and Pricing.** Since the SF Muni would have no market energy purchasing advantage and maybe even some disadvantage versus large national ESP firms, its only competitive advantages will be the ability to integrate some low-cost Hetch Hetchy power and the “trust factor,” as described above. Any potential melded energy cost advantages will depend on the size of the aggregated load. The bigger the program, the lower percentage of Hetch Hetchy power and the lower the discount, as limited Hetch Hetchy supplies are spread farther and farther.
- **Reliability.** No change from PG&E bundled services.
- **Local Control.** The Aggregator as an ESP would have the ability to structure rates, rules and regulations, and public benefits programs differently than those offered by PG&E. However, the state-mandated public benefit expenditures are financed by charges on the distribution system (PG&E). Any additional programs or any subsidy by one customer class of another customer class would likely lead to the loss to another competitor of that class doing the subsidizing. As a result, although local control would exist, its effective use may be limited by economic considerations.

### Community Aggregation

Community aggregation is still only a concept and depends on the passage of legislation, such as AB 117 (Migden) to even become an option. Under the current concept, the only potential provider would be a SF Muni or a Joint Powers Authority with San Francisco as a member. The key advantage of community aggregation, as compared to other forms of aggregation, is that on implementation, all customers not opting out would transfer to SF Muni energy service.

- **Rates and Pricing.** A SF Muni would be competing with regulated bundled services from PG&E or, if Direct Access is reinstated, with other ESPs and aggregators. The product served would be energy only. The financial advantages held by the SF Muni would be access to some low-cost Hetch Hetchy power and lower marketing costs due to the “opt-out” provision that defines this concept. Under AB 117 (as amended on June 5, 2002), customers would be obligated to pay the equivalent of exist fees to protect PG&E debt and to pay a share of

CDWR power cost obligations. From the standpoint of the cost of purchasing wholesale energy, the SF Muni would have no market advantage. Any competitive edge would depend on the percentage of the melded energy resources that are available from Hetch Hetchy or other San Francisco-owned resources. Without below-market cost resources, the SF Muni would have little, if any, competitive price advantage.

- **Reliability.** Reliability issues are the same as for the other forms of aggregation, i.e., no change.
- **Local Control.** This is the same as for Aggregator as an ESP. Local control would exist but the requirement for competition would dampen its effectiveness.

## Distribution Services

### Full Municipalization

A SF Muni (either the SFPUC or a new San Francisco municipal utility) would acquire the PG&E distribution system and provide fully integrated electric service.

- **Rates and Pricing.** Rate differences would depend on several key factors, including the cost of acquisition, severance costs, power supply costs, and any obligations to pay exit fees or other non-bypassable charges. Over time, exit fees and similar charges will diminish and finally go to zero. From the standpoint of price competition, it should be noted that PG&E rates reflect the same changes in price related to declining exit fees and non-bypassable charges.
- **PG&E.** PG&E, as an investor-owned distribution utility, is regulated by the CPUC. Rate levels are generally set on a Rate Base concept where PG&E is allowed to earn a Return on Investment (ROI) on distribution and customer service facilities and to recover its costs of O&M. The allowed ROI is established periodically based on a weighted cost of capital, including the melded cost of common stock, preferred stock, and debt. PG&E's weighted cost of capital can be expected to be relatively high due to its financial difficulties, including a reduction in its stock value and the downgrading of its debt. Most PG&E debt is taxable, although it has issued tax-exempt pollution control bonds.

PG&E pays property taxes and a franchise fee (normally 1% of gross revenues). They also pay federal and state income taxes that are paid before distribution of dividends to stockholders. The net effect of the high cost of capital plus taxes and franchise fees increases the cost of distribution service by 20 to 25% over what it would be for a publicly-owned utility that had built its own equivalent distribution system.
- **SFPUC.** It is assumed that the SFPUC would incorporate the distribution business within the Hetch Hetchy enterprise activity, allowing it to meld some below market cost hydroelectric power with bundled electricity services. Bundled rates would, therefore, reflect the following:
  - Lower costs of distribution due to a PG&E burden of 30% for combined taxes and profits.

## EXECUTIVE SUMMARY

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- Unknown higher costs of facilities depending on costs of acquisition and severance.
- Any power supply cost benefits from Hetch Hetchy.
- Potentially higher transmission costs due to higher San Francisco transmission costs versus PG&E system average.
- Higher average distribution costs due to the high cost of the downtown network no longer being averaged over the PG&E system.
- Lower residential distribution costs than average due to service area density. This may be offset in terms of cost per kWh by the relatively low use per average residential customer.
- Lower costs due to synergy between electric service and other SFPUC utility services. Examples include overheads, customer systems, metering, and billing.
- Somewhat higher costs of starting with an existing set of restrictive policies and procedures, work rules, and union agreements.
- Somewhat lower costs by starting with an existing work force and infrastructure.

It cannot be determined without in-depth analysis how all of these pluses and minuses work out in the short term. However, in the long term, if San Francisco is like other public power communities, it is likely to obtain a net cost advantage in the neighborhood of 20%.

- **San Francisco Municipal.** It is unclear whether a new and independent San Francisco municipal utility would obtain the benefits of below-market cost Hetch Hetchy power. For purposes of this discussion, it is assumed it would not. Bundled rates would, therefore, reflect all of the points noted for the SFPUC, with the following exceptions:
  - No power supply cost benefits from Hetch Hetchy.
  - No value of synergy with other utility services.
  - A need for a new customer care system.
  - The costs of setting up a new organization and infrastructure but with the benefits of starting from scratch.

As with the SFPUC discussion, there is no certainty as to the net effect of all the pluses and minuses. It should be noted that the pluses of the SFPUC approach could be maintained while the minuses are reduced by reforming the SFPUC in light of the needs of competition in the electric industry. The largest potential differentiator between the SFPUC and the San Francisco municipal utility approaches is the ability to make below-market cost Hetch Hetchy power available to San Francisco consumers.

- **Reliability.** Investor-owned and publicly-owned distribution utilities in California follow the same CPUC-approved construction standards and report service interruptions using industry standard indices. There have been instances where CPUC rate regulation has resulted in PG&E reductions in O&M expenses

(with attendant outage frequency increases). In the long term, it should be expected that overall distribution system reliability from PG&E would be equivalent to that which would be available from a San Francisco Municipal Utility.

■ **Local Control**

- **PG&E** is regulated by the CPUC, which is headquartered in San Francisco. The CPUC establishes rates, rules, and regulations for the entire PG&E service territory. Several years ago it eliminated the distinctions between service zones such that rural and urban communities pay the same rates even though their costs of service differ because of load density and weather-related customer load characteristics. About 3% of PG&E's total revenues, including those collected on behalf of the CDWR are committed to public benefit programs. The allocation of these revenues to each of four program categories was set by the Legislature. The further allocation of the revenues to specific programs is regulated by the CPUC or the California Energy Commission (CEC).

If a customer has a service or billing complaint that is not satisfactorily addressed by PG&E, their primary recourse is the CPUC. Although housed in San Francisco, the process of filing a complaint and ultimately being heard by the CPUC is lengthy and somewhat intimidating.

- The **SFPUC** is regulated by a commission that is appointed by the Mayor, resulting in a regulatory body that is one step removed from the voting public. Although it is still addressing local problems and local solutions, there may be a perception that it is not very responsive to the public. Other issues, such as historical experiences with water and wastewater services, joint cost allocations between enterprises and political concerns may all play into the effectiveness of this form of governance.
- A **San Francisco Municipal Utility** could be an independent agency with its own elected governing body. This would provide the opportunity for the highest level of local control. Constituents can directly communicate with their elected representative to address matters of community concern.

## **Conservation, Energy Efficiency, and Renewable Resources**

San Francisco is already doing more than most other communities in terms of promoting energy efficiency and in the development of renewable resources. The City's programs go beyond those funded with Public Benefit Funds collected by PG&E in connection with distribution services. The issue of local control over Public Benefit Fund expenditures is addressed in connection with elements of distribution system ownership. The most relevant considerations affecting the City's role in the electric business in connection with energy efficiency and renewable resources is the opportunity to assure integrated planning for all elements of electric service, including trade-offs between local central station generation needs, transmission capability, Distributed Generation, distribution system design, rates, and rules and regulations.

## EXECUTIVE SUMMARY

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As a fully integrated utility, a SF Muni could make integrated planning a foundation for all future facility additions and service standards. PG&E as an unbundled distribution utility is not ever again likely to be able to establish that type of foundation.

## Conclusions

San Francisco is at risk with regard to the cost and reliability of its power supply. Risk factors include:

1. Limited transmission into the Bay Area and San Francisco.
2. Old, inefficient, unreliable generation with insufficient capacity to provide self-sufficiency.
3. A changing electric industry regulatory structure that:
  - has resulted in, and will continue to allow, wholesale electric price volatility, and
  - will likely change retail pricing to more closely track wholesale costs and to penalize San Francisco for the combination of insufficient generation and transmission congestion.

San Francisco has the SFPUC that provides municipal electric utility services through Hetch Hetchy and owns hydroelectric generation and transmission that may not be used to its maximum economic value for San Francisco consumers. San Francisco also has the opportunity to employ other municipal approaches to providing energy services in San Francisco.

Expansion of municipally-provided electric service and reliability can be achieved through the SFPUC or other forms of organization and governance. Business roles and services that can be considered include:

- Ownership or participation in local generation and power supply markets with one or more of the following potential objectives:
  - Increasing local generation.
  - Substitution for existing generation to obtain reduced emissions and enhanced reliability and efficiency.
  - Serving retail load.
- Ownership or participation in expanded transmission to:
  - Enhance reliability.
  - Offset the need for some local generation.
  - Reduce the potential for congestion price effects on retail rates.
- Provide energy-related retail services via:
  - Aggregation as a Facilitator
  - Aggregation as an ESP

- Community Aggregation
- Provide integrated retail electricity services, such as:
  - Full municipalization of the distribution system
  - Spot municipalization
  - Services to loads adjacent to SFPUC facilities
- Increase efforts in conservation, energy efficiency, renewable, and Distributed Generation.

Each of these roles and services are discussed in the report as they relate to rates and pricing, reliability, and local control.



# Section 1

## REPORT PURPOSE AND ELECTRIC INDUSTRY STRUCTURE

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### Report Purpose

Reliable, reasonably priced electric service is vital to the economic health and public welfare of the City of San Francisco ("City"). During the past year, City residents and businesses have experienced unprecedented instability in the costs and reliability of their electric services. Given the bankrupt status of the City's current electric service provider and the uncertainty associated with the state's electric market structure, there exists public doubt as to the ability of PG&E and its state and federal regulatory authorities to properly meet the future electric service needs of the City. In response to these unique conditions, SF LAFCo instituted a series of public information hearings to gather information regarding the nature of the energy crisis, the likelihood of future problems, and what alternatives might be available to the City to avert such problems.

### Role of SF LAFCo

The SF LAFCo was formed in August 2000 as a result of an initiative petition to create a municipal utility district for the City and County of San Francisco and the City of Brisbane. Although this measure was narrowly defeated at the polls, the Commission determined that public hearings should be held to gather information from energy experts regarding the current utility service needs of San Francisco and the various options that may be available to increase service reliability, efficiency and cost effectiveness. These hearings are consistent with LAFCo's primary purpose which is to review public service needs, including utility service, and to determine whether new government entities should be created or changes in existing governments should be made to address the needs of its citizens.

From February 2002 until April 2002, the San Francisco LAFCo conducted a series of public hearings and representatives from the following public entities and private organizations provided presentations:

- SFPUC
- State of California Consumer Power and Conservation Authority (California Power Authority)
- CPUC
- PG&E
- Sacramento Municipal Utility District (SMUD)

## Section 1

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- Representative who managed utility department for the Cities of Anaheim, Palo Alto, Austin, Texas and Pasadena
- City of Roseville
- City of San Jose
- Onsite Energy Group specializing in cogeneration development and operation
- The Utilities Reform Network (T.U.R.N.)
- Northern California Power Agency

The information provided through the hearings is available through the LAFCo Executive Officer. At the conclusion of the hearings, the Commission determined that a study should be prepared to provide the public with information regarding the utility needs of San Francisco. A critical part of this analysis is an understanding of the various ways in which government can provide utility services to its citizens.

The Commission has taken the results of that public information process, and has commissioned this study, utilizing a number of electric energy experts, for the purpose of exploring the various alternatives of the City to receive its vital electric services, and in particular, to discuss how each alternative might address the following three key issues that affect electric service in the City:

- High energy prices
- Reliability (shortages and outages)
- Local versus statewide control to address energy issues and services

"Electric Service" involves a range of activities, including generation, power purchases, load forecasting, transmission and distribution, energy efficiency and conservation, metering, and retail customer services. Basically, there are only two vehicles or alternatives for providing these services: i) private companies (e.g. PG&E, its subsidiaries and other private companies); or, ii) municipal entities (as a utility, district or as a city).

This study will identify how each of these three key issues might be addressed by private companies or through one of the municipal forms (municipal utility, municipal district or city). The study will also assist the Commission in identifying the relative merits of pursuing some or all of these electric services through PG&E and other private companies, or, as an alternative, through some municipal form.

Finally, it should be noted that the matter of whether or not a particular electric service should be undertaken by a municipality, and in what manner, requires a complicated technical, legal, and financial analysis, involving a variety of factors beyond the scope of this study. This study does not go into the level of detail that would be necessary to conclusively evaluate the cost and revenues related to the various electric service activities (i.e. generation, power purchases, load forecasting, transmission and distribution, energy efficiency and conservation, metering, and retail customer services). Rather, this study discusses the relative level of expected costs and benefits of selected alternatives, and identifies areas in which further exploration is warranted.

More detailed economic studies would be needed after an appropriate municipal vehicle is selected (if one is selected), and after a governance body is established to oversee the scope and direction of such feasibility studies.

A key objective of this study is to assist in deciding whether it is prudent and advisable for the City to create or employ a municipal form (utility, district or city) as a vehicle to perform necessary feasibility studies and to develop implementation strategies for providing one or more “electric service” functions, as an alternative to the status quo.

### Electric Industry Yesterday

In response to the excesses of 19th century monopolies and trusts, the California Constitution in 1879 established a regulatory body known as the Railroad Commission to regulate certain essential utility services such as privately owned railroads, heat, light, power, water, and telegraph companies (*Calif. Const. Art. 12, Sec. 3*). This commission later became known as the CPUC. In exchange for receiving monopoly service territories, these regulated “public utilities” were allowed to charge “reasonable” prices for their services, as approved by the CPUC, that would allow these private companies to earn a “reasonable return on investment”. The “regulatory covenant” became the centerpiece of the relationship between the regulated (*i.e.*, the public utility) and the regulator, the CPUC.

At the same time that the Railroad Commission was created at the end of the 19th century, the California Constitution also provided an important alternative to California public agencies for providing such essential utility services. Article 11, Section 9, granted California cities the constitutional right to provide their own utility services (light, water, power, heat, transportation, or means of communication). To fully implement this constitutional right, municipalities were also given the full statutory power of condemnation. *Code of Civil Procedure Section 1240 et seq.* Thus, if regulation of a public utility failed to produce reasonable rates, the municipality could exercise its constitutional right to form its own municipal utility to provide that same service.

By the middle of the 20th century, there were three dominant private electric utilities in California, each regulated by the CPUC: PG&E, the Southern California Edison Company, and the San Diego Gas and Electric Company. These large utilities owned the vast majority of the transmission facilities in California and up into the Northwest, and in the 1960s began looking to nuclear power as a new source of meeting the increasing power demands of a rapidly growing California.

During that same time period, there were approximately 30 municipally-owned electric utilities, ranging from very small utilities to large ones like Los Angeles Water and Power and the Sacramento Municipal Utility District. In the mid-1960s, many of these municipal utilities made important choices as to their sources of energy. Some turned to the private utilities as their primary wholesale power suppliers, while others made long term commitments to purchasing their power from the federal government’s hydroelectric facilities pursuant to “preferential rights” under federal

law. Over time, the selection of hydroelectric power over nuclear power proved to be a very prudent one for such municipal utilities.

By the mid 1970s and 1980s, many of the municipal utilities became disillusioned with the prospect of purchasing their power supplies from the giant private utilities to meet their entire or supplemental needs, and formed joint power agencies for the purpose of sharing risks in the construction of new power plants and transmission facilities, and in otherwise meeting their future power supply needs. Again, this proved to be a prudent decision on the part of such independent-minded municipal utilities, as the differential in utility rates between the private utilities and municipal utilities began to widen in favor of the municipal utilities.

By the early 1990s, there was growing ratepayer dissatisfaction with high energy bills from the private utilities, especially compared with the national averages and with those of neighboring municipal utilities. There was also mounting disillusionment with the “regulatory covenant” and the ability of the CPUC to assure reasonable utility rates. Electric industry restructuring had already been initiated in some other countries and California followed suit with its own programs for regulatory change. At the same time of this regulatory reform for private electric utilities, municipal utilities around the nation were aggressively seeking access to the growing wholesale power markets through transmission reform at the FERC and at the state CPUC. The ability of the private electric utilities to forestall wholesale competition with municipal utilities by virtue of their monopoly ownership of the transmission grid was rapidly eroding. Clearly, change was in the air.

## Electric Industry Restructuring

In 1994, large commercial customers in California began a campaign to “deregulate” the electrical supply industry in an effort to reduce the cost of electricity and ultimately lower their production costs. California was in the midst of an economic downturn and energy-intensive businesses, such as aerospace and manufacturing, were moving out of state. In 1996, State Assembly Bill 1890 (AB 1890), authored by State Senator Steve Peace (D-El Cajon), was unanimously passed by the Legislature and signed into law by Governor Pete Wilson. AB 1890 was touted as the means to transition from a regulated, vertically-integrated, utility environment to unbundled electricity supply, transmission, and distribution markets, with the goal of reducing costs by creating competitive markets. The legislation, among other things:

- Allowed IOU customers to be able to purchase their energy from Energy Service Providers (ESPs) other than from their Utility Distribution Company (UDC), such as PG&E.
- Required IOUs to collect their stranded cost investment through a Competition Transition Charge (CTC), or fixed energy component, on all customers’ bills, even those under a new ESP.
- Established the CAISO and the California Power Exchange (PX) for transmission management and market trading.

- Strongly encouraged the IOUs to divest at least 50% of their thermal power plants through financial incentives.
- Required the IOUs to sell all output into the PX.
- Required the IOUs to purchase all needs from the PX day-ahead (and later, block forward) market and the CAISO's hourly real-time market.

The legislation was approved by the Governor on September 23, 1996. Diverse groups supported the bill, since there was something in it for each of them. IOUs were promised full recovery of stranded generation assets, consumers were given promises of rate reduction bond funded rate decreases, and industrial customers were given the promise of more competition.

### The Transition Period

At the outset of deregulation, the supply of generation available to California exceeded the demand by a fairly wide margin. Rather than selling 50% of their thermal generation assets, the IOUs divested nearly all of their thermal resources at multiples of book value. Wholesale electric prices were low but retail customers saw little difference in their bills due to the CTC. Few residential or small commercial customers made use of their ability to switch providers, since the CTC prevented them from achieving any real savings on their bills. However, about one-third of industrial customers exercised their option to switch ESPs because they were able to obtain discounts to tariff rates from ESPs anxious to establish a foothold in one of the country's first, and largest, restructured electric markets.

Between 1996 and 2000, the economy in California rebounded, creating new load growth (such as communications providers, dot-com companies, and internet service providers) that was not forecasted. Supply was limited as power plant developers were reluctant to build because of low market prices and state siting and permitting regulations. Growth in other Western states, particularly Nevada and Arizona that California relied on for generation, had accelerated leaving less power available for export to California. These changes initiated an imbalance between supply and demand for power that the new electricity market was expected to solve.

Much of the economic expansion fueled by the new dot com industry of the late 1990's occurred in San Francisco and the south Bay Area. The dot-coms brought new jobs, capital investment, and electricity demand growth to these areas at a record pace. All of the growth caused San Francisco's electric system to be taxed and transmission lines feeding the area to be congested. While utilities, the CAISO, regulators, generators, and customers had no reason to doubt that San Francisco's electric system could handle the new growth, the entire California electric system was being primed for failure.

### Problems Develop In 2000

Problems inherent in the implementation of deregulation began to surface in the summer of 2000. Sempra (San Diego Gas and Electric Co.) was the first IOU to recover its stranded cost, eliminate the CTC from its bill, and allow retail rates to

reflect spot-market (PX and CAISO) prices. Prices remained relatively low until May 2000 when wholesale prices began to dramatically increase as shown in the graph below that contains average monthly PX prices beginning in January 2000.

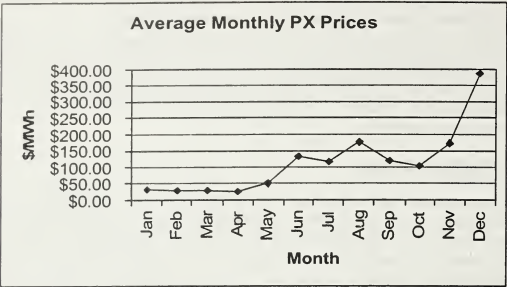


Figure 1-1: Average Monthly PX Prices

Customers of SDG&E had their monthly bills double and triple almost overnight. State legislators passed legislation that limited the generation component in San Diego’s rates to \$65 per MWh. The CAISO experimented with price caps that varied anywhere from \$150 to \$750 per MWh. The price caps failed to hold since the CAISO, on a real-time basis, had to purchase at almost any price in order to avoid blackouts. In the meantime, the debt of the other IOUs (Southern California Edison Co. (SCE) and PG&E mounted rapidly. With their rates still frozen by AB 1890, they were not able to recover the cost of power they purchased from the PX/CAISO.

Given the high market prices and mounting utility debts, California turned to the Federal Energy Regulatory Commission (FERC) for help. FERC responded by ordering changes to PX bidding, permitting IOUs to enter into bilateral contracts and giving IOU’s the freedom to trade through markets other than the PX. However, FERC refused to act on refunds or establish firm price caps in the Western U.S. Prices continued to rise and IOU’s facing mounting debts and a lack of revenue began to default on payments to power suppliers, bond holders, and creditors. Eventually, PG&E’s power purchasing debt led it to seek bankruptcy protection and SCE’s debt left it without investment grade ratings and with major cash flow problems. In spite of orders from the U.S. Energy Department, sellers were reluctant to sell either electricity or gas supply into California for fear of not being paid. The crisis peaked when for the first time since World War II, power was involuntarily curtailed on two days in January as the state’s demand exceeded the available supply.

San Francisco endured rotating outages ordered by the CAISO during these two days in January, 2001. With less than 30 minutes of warning, Blocks 3 and 4 were the first to receive rotating outages for up to 90 minutes. The outages affected businesses and

## REPORT PURPOSE AND ELECTRIC INDUSTRY STRUCTURE

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homeowners in San Francisco and stopped traffic at numerous major intersections. Critical public safety services, like hospitals, fire departments, and police stations were exempted from the blackouts. Throughout the city, the crisis triggered conservation efforts. At the Embarcadero Office Center, lobby lighting was reduced, elevator service was curtailed during power alerts, and pumps in the ornamental fountains were shut off. Altogether, the City was able to reduce electric demand by up to 20% on critical days. On January 23, 2001, Mayor Willie Brown stated, "(the blackouts) already had a profound effect on the city. We budgeted a certain number of millions of dollars for power, and in six months, that millions of dollars have disappeared. I am so worried about it that I am toying with the idea of putting the city and county of San Francisco in the energy generating business beyond its capacity currently."

In an attempt to respond to the electrical hysteria caused by blackouts and the price of power, the Governor declared a State of Emergency and authorized the CDWR to purchase power for delivery to the PX/CAISO. Today, the CDWR is the buyer of electricity for most IOU customers.

After declaration of the State of Emergency and enduring many months of high priced spot market power, some publicly-owned utilities had to raise rates. In addition, the CPUC granted both PG&E and SCE temporary rate increases averaging 4¢ per kWh. Even with the increases, reliability was still a major concern. Customers throughout California endured more rotating blackouts as supply and demand remained out of balance.

During the summer of 2001, when most utility experts were expecting the worst, a number of factors converged to mitigate the problem, avoiding additional blackouts. These factors included an economic downturn and aggressive conservation that reduced load by 10 to 15%, price mitigation measures adopted by FERC, the signing of long-term power supply contracts by the state, substitution of state credit for the IOU's lack of credit, and completion of new generation facilities. The following table summarizes the new environment created by these changes:

**Table 1-1**  
**Comparison of IOU and Muni Services**

| Issue                | IOUs                                                                                                                                            | Munis                                                                                                                                        |
|----------------------|-------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------|
| Vertical Integration | Still own distribution and transmission resources but have divested many generation assets                                                      | Are still vertically integrated, controlling generation, transmission, and distribution                                                      |
| Obligation to Serve  | Do not serve 100% of native load with own resources                                                                                             | Serve 100% of load in service territory with Muni managed resources                                                                          |
| Reserves/Debt        | Still have debt of about \$12 billion, although have collected substantial reserves from rate surcharges granted by CPUC                        | Most have created reserves to pay down debt and any stranded costs                                                                           |
| Direct Access        | New Direct Access contracts were suspended by the CPUC                                                                                          | Can still offer Direct Access if choose to do so                                                                                             |
| Restructuring Costs  | Continuing debt obligation for rate reduction bonds through 2007. Have continuing CTCs for power purchase contracts and nuclear decommissioning | Some are preparing to lower rates in the near future funded with stranded investment reserves and expiration of high priced energy contracts |
| CDWR Responsibility  | Must bill customer for power provided by CDWR, with excess costs estimated by CDWR at 2.39¢ per kWh                                             | None                                                                                                                                         |

## Outstanding California Issues

There are a number of issues in California that need to be resolved before a stable electric service environment can be expected. These include:

- The role of the CAISO and its survival is in question. FERC is pushing for Regional Transmission Organizations (RTOs). Some California publicly-owned utilities, in an attempt to avoid unfair and escalating CAISO charges, are seeking to form their own control areas. FERC ruled on January 29, 2002, that the governance structure of the CAISO was not satisfactory in that it was not sufficiently independent and that it would have to be modified.
- FERC is considering and implementing market surveillance and reporting mechanisms so that past price abuse is not repeated in the future. At this point, it is unclear if price controls will remain in place beyond September 2002, or if FERC will order refunds for past abuse.
- The CAISO has proposed a Comprehensive Market Design that could have major implications for the delivered cost of power to Bay Area consumers, and could affect the viability of some municipal energy services options.
- The status of Direct Access is uncertain. The date by which a Direct Access customer had to be signed up for Direct Access may be revised to July 1, 2001 (now September 20, 2001), because of concerns about the amount of load that is purported to be exempt from non-bypassable charges (14%). Additionally, Direct Access may be reinstated for certain types of customers, for some percent of all

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customer loads, or made available if Direct Access customers pay a surcharge to compensate for the stranded cost portion of CDWR power purchase commitments

- The CPUC is currently investigating a means to return the obligation to serve 100% of native load to the IOUs. The expected date of implementation is January 1, 2003.
- There will need to be a resolution of how and to what extent the IOU debts, the high cost of CDWR power supply purchases, and remaining stranded investment and AB 1890 transition costs will be recovered.



## Section 2

# WHOLESALE POWER MARKET COSTS AND RISKS

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## Introduction

Henwood Energy Services, Inc. has been retained to provide the following information to support SF LAFCo's study options for the provision of energy services to the City and County of San Francisco:

- Overview of the wholesale power market
- Identification of wholesale market risk factors facing Load Serving Entities and opportunities to mitigate those risks
- Position Report for the CAISO-defined San Francisco area
- Assessment of wholesale power market costs for the City of San Francisco under three supply portfolio scenarios

## WECC Wholesale Power Market – Background

Before the City and County of San Francisco can determine how to meet its electricity service needs, it must under the issues related to the wholesale power market in a broad context. Not only do the issues need to be addressed from a California perspective, but also from a perspective that considers the electrically interconnected western North America.

This larger interconnected area in North America is referred to as the Western Interconnect. The WECC, one of 10 electric reliability councils in North America, is responsible for coordinating and promoting electric system reliability in the Western Interconnect. The Western Interconnect and the WECC encompass the same geographic area. The WECC is the second largest of the three interconnected grids in North America. The WECC encompasses 1.8 million square miles and includes all or portions of 13 western states, two Canadian provinces, and a portion of Mexico. With some limitations, generation from any area of the WECC can be used to meet electric load in any other area of the WECC. The transmission ties between the sub-regions of the WECC are good, albeit not perfect. Historically, wholesale electricity spot prices have been highly correlated across the WECC. California is a geographic portion of the Western Interconnect and its load makes up about 39 percent of the total electric load in the WECC.



## Section 2

Figures 2-1 and 2-2 provide key characteristics and price drivers of the WECC. Figure 2-1 provides an overview of the WECC and the current status of project development.

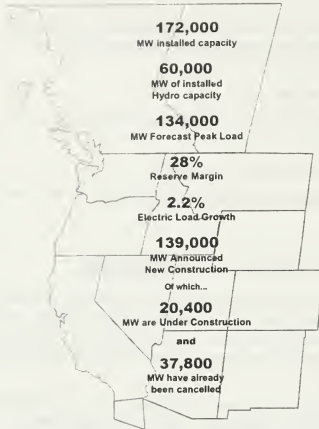


Figure 2-1: WECC at a Glance

The generation mix in the WSCC is shown in Figure 2-2. The hydroelectric generation portion in WSCC is higher than the national figure. At the present time, hydro accounts for 36 percent of the installed capacity. While hydro is cheap and renewable, it does have its problems. From an electricity standpoint, the amount of power coming from hydro electric generators in each hour, day, month and year is driven by a number of factors. Rain and snowfall are the lifeblood for hydroelectric supply. If it is a wetter than normal year, hydroelectric generation is better than expected. If there is a severe drought, generation supply in the west can become very tight. Hydro generation is also subject to a number of non-power constraints including flood control, irrigation, recreation, fish needs, etc.

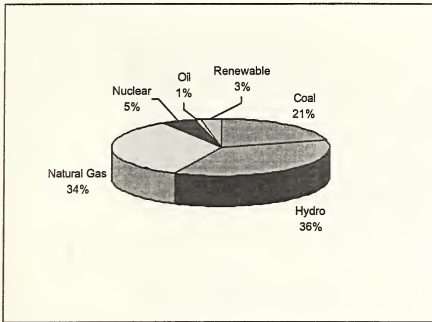


Figure 2-2: WECC Installed Capacity by Fuel Type - 2001

## What went wrong in 2000 and 2001?

There were many factors that contributed to the recent electricity crisis in California and the Western United States. AB 1890 promised to achieve a number of goals for California energy consumers including lower electric bills and choice of generation providers. A key to realizing these goals was a continued adequate supply of electricity and a properly functioning market. Unfortunately, the Western United States ran into a severe shortage of electricity and investigations are ongoing regarding market manipulations and other broken aspects of the market. This caused severe problems for California and the WECC. Some of the key aspects that created those problems were as follows:

- **Lack of new resources:** The WECC experienced robust economic growth in the last decade, resulting in increasing demands for electricity. For a number of reasons, construction of new power plants did not keep up with demand growth. The developing supply shortage was masked for a few years by the fact that hydroelectric generation supplies in the late 1990s were more plentiful than normal because of abnormally high precipitation and snow pack.
- Figure 2-3 below provides an overview of new construction since 1991.

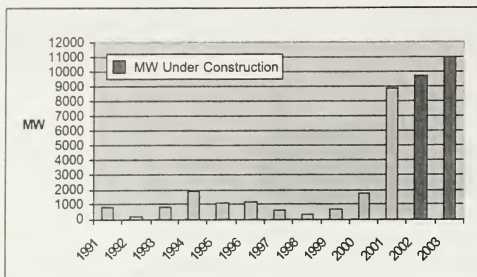


Figure 2-3: Construction of New Generating Resources in the WECC

- **Large exposure to Spot Market power:** Throughout the history of power markets in the WECC, the bulk of wholesale power was produced under arrangements that resulted in long-term fixed prices. However, under the California AB 1890 legislation, the California private utilities were required to sell large quantities of their long-term stable price resources and substitute power that would be procured in spot markets. With such a large proportion of the private utilities' power being purchased from the spot market, the utility financial costs for purchased power was dependent on that key assumption of low and stable prices.
- **Retail rates frozen at low levels:** In passing AB 1890, California legislated a 10 percent rate decrease for California retail electric customers of the IOUs and required that the rates be frozen at these lower levels until the earlier of (a) the date the IOU had fully recovered its stranded costs, or (b) until March 2002. This retail rate cap had two effects. First, it resulted in few customers changing their generation provider. Second, in conjunction with the requirement that IOUs be exposed to spot market wholesale power prices, the retail rate cap set up the possible scenario where wholesale purchases could be very high priced while retail prices would be capped at low rates. In essence, the IOUs could be forced into a scenario of "buy high, sell low."

In May of 2000, there was a realization that hydro generation in the West (primarily the hydro rich Pacific Northwest) would be much less than normal in the summer of 2000. That fact, coupled with unexpectedly high loads caused by warmer than normal May temperatures in California and other western states, created an unanticipated shortage of supply in the WECC. Spot prices jumped to unanticipated high levels. Throughout the summer of 2000, the WECC experienced a shortage of hydroelectric generation and historically high natural gas prices. Figure 2-4 presents an historical perspective of natural gas prices and illustrates the severity of the gas price spikes.

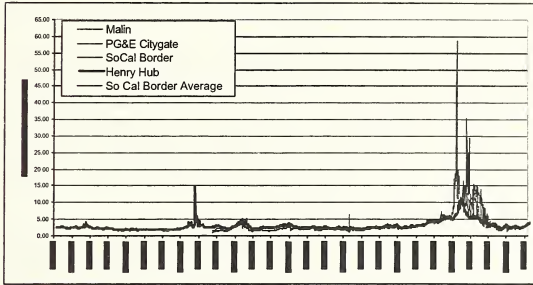


Figure 2-4: Natural Gas Prices in the West, 1993-2002

The result of this combination of events was historically high wholesale power prices, as shown in Figure 2-5, below:

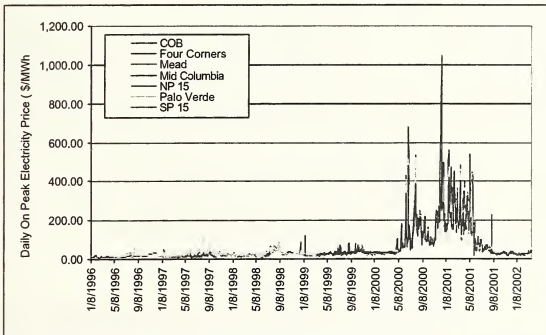


Figure 2-5: Daily On Peak Prices for WECC Market Areas, \$/MWh

Exacerbating the fundamentals that led to high prices may have been manipulation of the electricity and gas markets. The FERC is examining now-bankrupt Enron's role, as well as the role of over a hundred other trading firms and utilities outside of California, in the soaring electricity prices experienced in California and the Northwest.

### Henwood's Near-Term Outlook

Compared to California's 2002 experience, today's outlook for the supply of electricity at reasonable prices is very different and positive. The severe supply shortages plaguing the WECC in 2000 and 2001 are history. The region has now returned to more than adequate reserve margins driven by the competitive market forces that responded to the shortage of energy and capacity. Increasing supply, the impacts of recession and customer conservation that lowered demand, and the return to a normal hydro year have pushed wholesale electricity prices substantially downward, prompting many developers to cancel, defer, or postpone projects previously announced and/or under construction.

Despite recent project cancellations and a worsening liquidity crisis affecting developers, more capacity is now under construction than nine months ago. There is a significant amount of capacity in the pipeline, which will be completed during the 2002-2004 period. Nonetheless, the impact of competition in the wholesale power markets has dramatically reduced the reaction time for market correction in the current boom and bust cycle.

As the market works off the surplus margins caused by so much new construction and as loads return to more normal levels, the capacity surplus is expected to disappear by 2009 and market prices will increase to more long run equilibrium levels.<sup>1</sup>

However, against this background of current healthy reserve margins and depressed prices, price volatility is expected to remain a permanent fixture of the competitive market, creating risks for load serving entities (LSE). This has created significant opportunities for traders and generators offering hedging and/or long-term, fixed price contracts. Many LSEs are now attempting to reduce their risk exposure by relying on a mixture of long-term and spot market options, appropriately hedged against rising prices.

Henwood's recent study of the WECC contained several conclusions and insights regarding wholesale electric prices in the future. These include:

- wholesale electricity prices in the WECC region will likely remain *stable* and *slightly depressed* in the short run under reasonable assumptions;
- there will be a *comfortable reserve margin*—for the foreseeable future;
- there could be sub-regional capacity shortages;
- there will be *considerable uncertainties* which can affect projected prices depending on assumptions about economic and load growth in the region, hydro conditions, availability and price of natural gas, the amount of new resources that may come on-line; and regulatory and policy issues affecting transmission and market design.

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<sup>1</sup> As defined here, capacity surplus exists if (nameplate capacity – load)/ load > 20%. This is not meant to imply that new projects could not still be economic.

## **Wholesale Market Risk Factors**

The City of San Francisco, if it chooses to operate as an independent load serving entity will need to immediately begin exploring its options for reliably serving the growing load of the City consistent with the need to minimize costs without taking on an inappropriate level of risk. Other load serving entities in the west have learned the hard way that if they do not have an integrated resource plan for managing both load and resources in their system, they can easily become over-exposed to market volatility and incur huge financial losses – either by having too much dependence on the spot market or by over-subscribing to higher cost firm contracts. Two notable examples to both signs of this coin include Seattle City Light and CDWR. Seattle City Light got caught short on generation in the recent drought due to its high dependence on hydro generation. CDWR, due to politics, inexperience, and a need to attempt to tame the California energy market, entered into high-cost contracts, the output of which when combined did not perfectly match the expected net short position of the California utilities.

The recent electric market events highlight the need for Integrated Resource Planning (IRP). IRP started as a regulatory-driven requirement in the late 1980s and early 1990s. It fell by the wayside as market restructuring was introduced in California in the mid 1990s. Now it is making a comeback as price volatility and over-exposure to risks has made everyone aware of the dangers of not having an integrated resource plan and a balanced portfolio. Some utility commissions are now re-emphasizing integrated resource planning. Even when there is no regulatory requirement to do an integrated resource plan, LSEs are doing it under their own volition. It simply makes good business sense to have an integrated resource plan.

Volatility and uncertainty places particular demands on load-serving entities. The experience of many utilities in the west has clearly demonstrated that reliance—whether voluntary or forced—on spot markets carries very significant risks. Forward contracting, whether bilateral or through exchanges, is essential.

Risk, in the context of this report, means an uncertainty in the future state of a variable that can have a significant influence on the financial performance of an entity participating in the power markets. Risk can be segmented into long-term and short-term components.

Longer-term risks are those that could have a significant impact on the long-term—i.e., over several years—economic viability of a market participant. These longer-term determinants tend to be tied to the investment behavior of generation capacity developers and overall economic conditions, the value of which can be captured through measures such as gross domestic product (GDP). The relevant long-term risks are: demand uncertainty, supply risk, fuel price risk, market regulatory uncertainty, environmental regulatory uncertainty, and technological changes.

As the time horizon shortens into a perspective of a year or less, the determinants of wholesale electricity prices change. Changes in both demand and supply will affect short term electricity prices. The major source of demand fluctuation is weather, principally temperature, which influences variation in load from hour to hour and day

to day. On the supply side, the three major causes of price fluctuations are seasonal hydroelectric potential (i.e., weather), fuel price, and generating equipment outages, although transmission equipment outages or transmission congestion can also significantly impact prices. These major short-term determinants—weather, fuel price and equipment outages—are mean reverting variables (i.e., their long term or equilibrium values are accurately represented by their mean or expected values).

For the purposes of this discussion, risks have been categorized into primary, secondary, and tertiary classes, reflecting a decreasing level of risk based on empirical evidence and Henwood's expert opinion. The key determinants are listed below, along with their risk categorization:

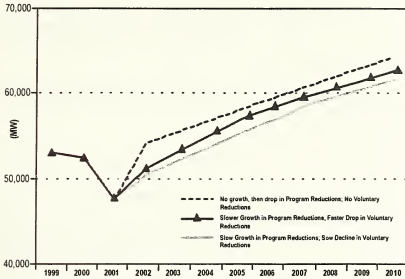
**Table 2-1**  
**Risk Characterization**

|                 | Short-Term                        | Long-Term                                         |
|-----------------|-----------------------------------|---------------------------------------------------|
| Primary Risks   | Weather<br>Outages<br>Fuel Prices | Demand Uncertainty<br>Supply<br>Fuel Prices       |
| Secondary Risks | Transmission                      | Market Regulation                                 |
| Tertiary Risks  |                                   | Technological Changes<br>Environmental Regulation |

Each of the risks outlined above are described in the following paragraphs.

**Long-Term Demand Uncertainty.** Uncertainty in long-term average demand, or consumption, is created by underlying uncertainty in both the growth rate of overall economic activity (GDP) and the average level of electricity consumption per unit of economic activity (kWh / \$ of GDP). Electricity consumption is highly correlated with macro-economic growth over the long term, and annual changes in consumption are similarly correlated with changes in growth. Consumption per unit of GDP, in contrast, grew steadily until 1976, and has been declining ever since as the U.S. economy moves increasingly from industry to services. The use of air conditioning has become more widespread and as a result, annual "load factors" have been declining steadily, resulting in load profiles with higher peaks.<sup>2</sup> To capture these trends, Henwood uses demand forecasts created by individual Load Serving Entities (LSEs) and reported to the U.S. Department of Energy (and other similar sources). These demand forecasts are used by regulators and utilities for regional planning purposes, and explicitly account for both consensus forecasts of regional growth and changes in electricity consumption per unit of GDP. Figure 2-6 shows the California Energy Commission's representation of uncertainty in load growth in California. The crisis of 2001 was resolved through dramatic decreases in loads in the region (both within California and the WECC as a whole). Henwood expects that with lower prices and economic recovery, demand growth will return to normal levels.

<sup>2</sup> Load factor is equal to average annual demand [in MWh] / (peak demand [in MW] x 8,760).



Source: California Energy Commission.

Figure 2-6: Uncertainty in Load Growth in California, 1999-2010

**Long-Term Supply.** Electricity prices are heavily influenced by the supply of electricity available from other generating units in a region. This supply, in turn, will change with the addition of new capacity, the refurbishment or enhancement of some existing capacity, and the retirement of other existing generation units. In theory, at equilibrium, the amount of capacity entering the market each year will be such that the last entrant is able to recover its costs and earn a reasonable return on capital invested. Such an equilibrium will produce a reserve margin sufficient to provide reliability without depressing prices to the point where new generation does not earn its anticipated return. In practice, the addition of new capacity is driven by the investment cycles typical of capital-intensive commodity industries, the timing, magnitude and duration of which are inherently uncertain. While an overbuild situation can result from such cycles, the discipline of capital markets that provide funding for new capacity provides a natural mitigant against sustained excess supply.

**Long-Term Market Regulatory Risk.** This risk manifests itself in the uncertainty surrounding the ultimate long-term regulatory structure of the WECC and California markets, as well as the “overhang” that occurs from the long-term purchases of power by the California Department of Water Resources. Although several initiatives are underway, there is currently no strong central independent authority for coordinating the WECC market. It is likely, however, that such an entity, in the form of an ISO or RTO<sup>3</sup> will eventually be created. Consistent with their purpose, these organizations would likely ensure equal market access, administer the transmission system on an equal and non-discriminatory basis, and help maintain competitive markets for energy and ancillary services.

California’s dysfunctional electricity market coupled with the retail rate freeze placed two major investor-owned utilities (IOUs) in an untenable position, jeopardizing their

<sup>3</sup> Independent System Operators (ISOs) and Regional Transmission Authorities (RTOs) are two forms of regional market organizations proposed by the Federal Energy Regulatory Commission (FERC).

financial health. California Department of Water Resources (CDWR) has been securing their net short position since January 2001. The same agency signed long-term contracts to buy power from generators in an attempt to stabilize retail prices and reduce the dependence of the volatile spot market.

Prices have calmed in the WECC and California market, and the IOUs appear to be on the road to slow recovery—although the process promises to be protracted and difficult. In the mean time:

- California is attempting to renegotiate its \$42.8 billion obligations—having asked FERC to nullify the contracts. On April 22, 2002, California state officials announced that they had restructured eight of CDWR’s long-term energy contracts. The renegotiated deals affected four contracts with Calpine, one with High Desert Power Plant LLC (Constellation Energy Corporation), and three contracts with renewable energy providers—Capitol Power, Cabazon, and Whitewater Hill. On May 2, 2002, CDWR announced that it had also restructured contracts with CalPeak Power. The new contracts call for the termination of one of seven peaking projects, shortening the term of another, and reducing the cost of the remaining projects;
- The state is also attempting to issue \$11.1 billion worth of revenue bonds to be financed through rates collected by the IOUs;
- The California Public Utilities Commission (CPUC) has officially ended direct access, and has proposed a controversial exit fee for customers who have switched suppliers and do not wish to return to high, regulated tariffs;
- CPUC wants the IOUs to start procuring their power needs beginning January 2003; and
- Under pressure from FERC, California ISO is examining market design alternatives as well as the issue of whether it is independent enough to meet FERC criteria for an ISO.

**Table 2-2**  
**Largest Long-Term Contracts Signed by the California DWR**

|                      |                |
|----------------------|----------------|
| Calpine              | \$11.7 billion |
| Sempra Energy        | \$6.6 billion  |
| Williams             | \$4.6 billion  |
| Allegheny Energy     | \$4.4 billion  |
| Constellation Energy | \$3.9 billion  |

*Source: California Department of Water Resource, 2002*

Oregon, Nevada, and Washington have experienced similar problems. How these difficult financial, regulatory, and legal issues are sorted over the coming years will have a significant bearing on the evolution of markets and prices in WECC.

Perhaps the most significant risk is with either activation of the SF Zone under the current zonal pricing scheme of the CAISO or more likely, the eventual movement to Locational Marginal Pricing (LMP).

**Locational Marginal Pricing.** In most markets in the US, electricity prices on the grid are determined on a “Market Clearing Price” basis; a common industry practice. Economists refer to this as an equilibrium price. Buyers are charged the price paid for the last block of power needed to satisfy demand. Dispatchers use the lowest priced generators first, bringing more expensive units on-line as needed so that the last used is also the most expensive.

This structure, which treats a market area as a single unit, does not address an important variable -- the location of supply and demand. Transmission grids suffer from traffic congestion as certain key transmission lines reach maximum capacity at times of high power demand. When lines become congested, using the lowest cost generator may not be possible. Many markets in the US are now moving toward an economic solution to this problem – Locational Marginal Pricing – or LMP. LMP is a flexible pricing system that reflects differences in electricity production costs, locations of generators and users, and total system demand. LMP is the marginal cost of supplying the next increment of electric energy at a specific location (node) on a network, taking into account both generation marginal cost and the physical aspects of the transmission system.

As will be discussed in Section 3, the City of San Francisco faces some particularly critical risks related to transmission constraints and the fact that those constraints as they exist today are likely to cause Bay Area users to pay higher prices than the rest of the PG&E territory unless congestion is reduced through the addition of new transmission and/or new generation. Currently, PG&E spreads the costs of congestion among its rate classes. In the future, consumers of electricity in geographic areas that experience congestion – such as San Francisco – may be required to pay more directly the costs of that congestion via LMP. The cost of congestion could become a significant factor in the price of electricity in San Francisco.

The FERC recently issued its “Working Paper on Standardized Transmission Service and Wholesale Electric Market Design.”<sup>4</sup> This paper sets forth FERC’s policy guidance to achieve “... robust, seamless competitive wholesale electric markets.” San Francisco is vulnerable to loss of local generation and loss of transmission, which could increase its exposure to high LMPs.

**Regulatory Risk.** The electric power industry is subject to numerous regulations. It is difficult to forecast what regulatory requirements will be in the future. While FERC is leaning toward competitively determined prices, it has the authority to cap prices and mandate other rules. Environmental requirements can change in ways that impact the economics of generation and wholesale power prices.

**Technological Change.** Technological change in the electric utility industry constitutes risk primarily in terms of new generation sources that could compete with or replace existing generation sources. The two likely potential sources of such new

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<sup>4</sup> See FERC website, <http://www.ferc.fed.us/Electric/RTO/Mrkt-Strct-comments/e-1finalSMD.PDF>

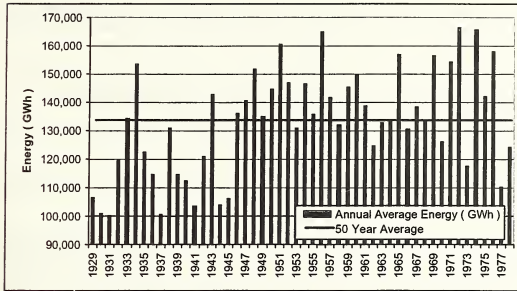
capacity are distributed generation and electricity storage. Entry of distributed generation into the electricity generation market can best be viewed as a “niche play” and the total market entry may well be limited. Energy storage technologies are best suited for “power quality” enhancing uses. These applications require lower power capacities, shorter service duration, and quicker response times than available from conventional electric generation technologies, and therefore compete in a different market niche.

For LSEs, technology can represent an opportunity for wholesale power purchases it makes in the spot market. Technology can also be viewed as an opportunity cost in that an LSE that locks in most of its portfolio into long-term contracts at the cost of a current technology may “leave money on the table” when new, lower cost technologies enter the market.

**Short Term Demand Risk (Weather).** The price of electricity on an hourly basis tends to vary dramatically in response to load demand. Weather conditions have an overriding impact on hourly load demand patterns. For example, the difference between an average summer day and a very hot summer day will be that the level of electricity usage will be markedly higher, as consumers run more air conditioning units. Weather also has a secondary impact on the availability of resources. Some types of generating technology, particularly combustion turbines, have lower maximum capacities in hot weather.

**Short-Term Supply (Hydro).** The WECC, more than other parts of the country, is heavily dependent on hydro generation. California, in particular, has traditionally relied on inexpensive hydro imports from the Pacific Northwest, notably during the hot summer months. This reliance, and the 2000-01 drought, was one of the chief contributors to high prices and price volatility during the California market crisis.

The relative significance of hydro gradually diminishes over time as more thermal units are added to the WECC system—but hydro will remain significant for years to come. Another prolonged drought, for example, can significantly reduce WECC’s perceived high reserve levels and seriously affect prices in the region. The fact that hydrological conditions cannot be predicted with any degree of certainty makes this a major wild card in the WECC. Environmental and operational restrictions, notably for preservation of endangered salmon species, will add to these uncertainties. Figure 2-7 below illustrates the impact hydro conditions in the Northwest have on the availability of power. For example, the impact of a dry hydro year such as that which occurred in 1937 or 1977 is equivalent to the loss of about 4,500 MW of combined cycle power plants from the WECC system.



Source: BPA Whitebook, 1999

**Figure 2-7: Annual Average Energy available from Northwest Hydro Projects 1929-1978; GWh**

The implications of the hydrology on the WECC are that there is a demand for weather-oriented derivatives—but such hedges remain expensive. Given that Hetch Hetchy's resource portfolio is hydro-based, hydro variability is a particularly important variable for San Francisco.

**Short-Term Supply (Outages).** The supply of electricity varies with time, both on an hourly basis, and on weekly and seasonal bases. The variation is a direct result of the nature of the resources that supply electricity—they are mechanical systems with the potential to break down (a “forced outage”) and the need for periodic maintenance (a “maintenance outage”). Since electric storage is relatively expensive, most electricity is produced at the moment of consumption. These two factors, the occurrence of outages and minimal storage capability, lead to significant variation in the resources available to supply electricity, and corresponding variation in price. This price variation is explicitly captured in Henwood's structural simulation of electricity markets through an allowance for maintenance outages and a representation of forced outages.

**Natural Gas Price.** Natural gas prices are historically quite volatile. Increases in gas prices increase operating costs of gas-fired generation which, in turn, will normally result in higher prices for wholesale power. Reductions in natural gas prices will tend to lower prices for wholesale power. The market provides various methods for managing this gas risk.

**Transmission.** The risk associated with transmission systems is that trading parties are not always able to transmit the amount of energy that would be desired in the case of an unconstrained system. Such transmission congestion leads to price disparities among regions and contributes to electric price volatility. Congestion is caused because the transmission system has physical limits that restrict the amount of energy

transported. These “path limits,” and the risks they create, are captured in Henwood’s analysis by incorporating the path limits explicitly in the deterministic model. . San Francisco is located in an area that is subject to transmission constraints.

## Growing Prominence of the Energy Marketplace

The embedded energy market risks described above have spawned new players in the electric industry in the last several years. Clear federal policy and many state regulatory initiatives are encouraging competitive market forces and a growing independent supply sector. Many states are also experimenting with or instituting retail competition as well.

Beginning with the Energy Policy Act of 1992, the federal government has pursued an initiative under which there would be robust competition in wholesale power markets. New players (Independent Power Producers) have been encouraged to build new generation facilities and provide the power to traditional utilities (now called load serving entities). Other new players, sometimes called “energy merchants,” have developed business models that negotiate short- and long-term deals to buy and supply electricity and then use trading skills to maximize the value of those deals. The ability to originate agreements to buy and sell, to price risks appropriately, and to decide whether to keep or shed specific risks is a special skill that these companies have developed.

Energy merchants (such as Dynegy, Mirant and Reliant) pursue national and even global opportunities. They are open to owning power plants but equally open to controlling generation output through properly structured contracts. Many national or global merchants trade not only electricity but also gas and other related commodities. Indeed, the recent volatility of U.S. gas prices has highlighted the need for upstream players to be skilled in multi-commodity risk management. Many believe that electricity markets will move toward greater efficiency and liquidity, a development that will in turn place downward pressure on margins for even the most skilled competitors. Energy merchants offer a wide variety of products for meeting energy needs. A product could be a short-term or long-term firm “forward” or “future” purchase/sale.<sup>5</sup> A product could be an “option” where a premium is paid against a right to buy or sell at a specific price, or a derivative or other exotics. A product could be a right to “toll” gas through the merchant’s gas-fired generator. A product could be a financial product that, for example, “swaps” a fixed power price for a volatile spot market price.<sup>6</sup> Under such an arrangement, the City could decide to buy

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<sup>5</sup> Forwards are over the counter traded, with counter party risk. Forwards products are often custom negotiated to meet the needs of both parties. While forwards can be cash settled, they typically settle with physical delivery. Futures are traded in exchanges where parties do not know who the counter party is and there is no counter party risk. The Exchange itself takes on the credit risk and requires traders to be credit worthy. Future products necessarily need to be standardized. While futures can result in physical delivery, typically they “cash” settle based on change in value relative to the spot.

<sup>6</sup> All financial products involve some exchange of risk between fixed price and floating spot price.

its needs via the day ahead spot market but avoid the volatility in prices in such spot markets.<sup>7</sup>

In addition to encouraging new players to participate in wholesale power markets, the federal government has adopted the theory that competition will hold down wholesale power rates and that therefore wholesale power rates no longer are based on the cost of the power supplies. Similarly, prices for natural gas commodity and bulk natural gas transmission have been deregulated.

## **Focused Assessment of the City of San Francisco**

The qualitative discussion of the WECC and California markets and associated risks must be accompanied by a specific assessment of the position of the City of San Francisco with respect to the forecast of load it will need to serve, the options for acquiring the generation to serve that load, and the costs of that generation.

This section will first briefly review Henwood's forecast of San Francisco's current and future position – a forecast of load requirements and how that compares to the available resources within the local area and the transmission capability to make up any shortfall with imports. Following the position report, Henwood estimates for SF LAFCo the costs of wholesale power to serve that load. Three supply scenarios will be reviewed.

## **Load and Resource Report for San Francisco**

San Francisco currently has an annual peak demand of approximately 900 MW. That peak is generally experienced some time during the months of September through November. Annual energy consumption in San Francisco is currently estimated at 5,500 GWh, or approximately seven percent of PG&E's total retail load.

Table 2-3 is a load and resource report for the City of San Francisco. The table shows the annual forecast of peak loads in the City, the expected energy requirements, the local area generation, and import capability for the period 2002 through 2012. As can be seen, the area relies extensively on imports and will in the near future come under risk of blackouts unless much discussed transmission and generation additions materialize.

Table 2-4 is a load and resource report on a monthly basis for the year 2003.

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<sup>7</sup> There may be concern that while this kind of swap arrangement may provide price protection, it may not provide a reliable supply. It would be important to monitor WECC-wide reserve margins (existing and forecast) in order to ascertain if relying on such an arrangement might be a reliability risk or not.

**Table 2-3**  
**Annual Load and Resource Report – San Francisco**  
**2002-2012**

**Annual Coincident Peak Hour**

|                             | 2002          | 2003          | 2004          | 2005          | 2006          | 2007          | 2008          | 2009          | 2010          | 2011          | 2012          |
|-----------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|
| <b>Load</b>                 |               |               |               |               |               |               |               |               |               |               |               |
| Peak Load (MW)              | 920           | 960           | 993           | 1,035         | 1,056         | 1,079         | 1,100         | 1,121         | 1,130         | 1,150         | 1,170         |
| Annual Energy (GWh)         | 5,715         | 5,848         | 5,929         | 6,183         | 6,309         | 6,443         | 6,571         | 6,698         | 6,751         | 6,868         | 6,990         |
| <b>Resource</b>             |               |               |               |               |               |               |               |               |               |               |               |
| Thermal (MW)                | 722           | 584           | 584           | 584           | 584           | 584           | 584           | 584           | 584           | 584           | 584           |
| Hunters Point 2             | 52            | 0             | 0             | 0             | 0             | 0             | 0             | 0             | 0             | 0             | 0             |
| Hunters Point 3             | 86            | 0             | 0             | 0             | 0             | 0             | 0             | 0             | 0             | 0             | 0             |
| Hunters Point 4             | 163           | 163           | 163           | 163           | 163           | 163           | 163           | 163           | 163           | 163           | 163           |
| Hunters Point GT1           | 52            | 52            | 52            | 52            | 52            | 52            | 52            | 52            | 52            | 52            | 52            |
| Potrero 3                   | 207           | 207           | 207           | 207           | 207           | 207           | 207           | 207           | 207           | 207           | 207           |
| Potrero GT 4                | 54            | 54            | 54            | 54            | 54            | 54            | 54            | 54            | 54            | 54            | 54            |
| Potrero GT 5                | 55            | 55            | 55            | 55            | 55            | 55            | 55            | 55            | 55            | 55            | 55            |
| Potrero GT 6                | 53            | 53            | 53            | 53            | 53            | 53            | 53            | 53            | 53            | 53            | 53            |
| Firm Import (MW)            |               |               |               |               |               |               |               |               |               |               |               |
| BPA to BART                 | 66            | 66            | 66            | 66            | 66            | 66            | 66            | 66            | 66            | 66            | 66            |
| <b>Total Resource (MW)</b>  | <b>788</b>    | <b>650</b>    | <b>650</b>    | <b>650</b>    | <b>650</b>    | <b>650</b>    | <b>650</b>    | <b>650</b>    | <b>650</b>    | <b>650</b>    | <b>650</b>    |
| <b>Reserves (MW)</b>        | <b>-132</b>   | <b>-310</b>   | <b>-343</b>   | <b>-385</b>   | <b>-406</b>   | <b>-429</b>   | <b>-450</b>   | <b>-471</b>   | <b>-480</b>   | <b>-500</b>   | <b>-520</b>   |
| <b>Reserve Margin (%)</b>   | <b>-14.3%</b> | <b>-32.3%</b> | <b>-34.5%</b> | <b>-37.2%</b> | <b>-38.4%</b> | <b>-39.8%</b> | <b>-40.9%</b> | <b>-42.0%</b> | <b>-42.5%</b> | <b>-43.5%</b> | <b>-44.4%</b> |
| <b>Import Capacity (MW)</b> | <b>730</b>    | <b>730</b>    | <b>730</b>    | <b>730</b>    | <b>1130</b>   | <b>1130</b>   | <b>1130</b>   | <b>1130</b>   | <b>1130</b>   | <b>1130</b>   | <b>1130</b>   |

Note: Hunters Point 2 and 3 are currently operating as synchronous condensers and do not contribute power to the grid

Table 2-4  
Monthly Load and Resource Report – San Francisco  
2003

| Load                 | Monthly Coincident Peak Hour |          |        |        |        |        |        |        |           |         |          |          |
|----------------------|------------------------------|----------|--------|--------|--------|--------|--------|--------|-----------|---------|----------|----------|
|                      | January                      | February | March  | April  | May    | June   | July   | August | September | October | November | December |
| Peak Load (MW)       | 896                          | 877      | 873    | 873    | 874    | 925    | 875    | 874    | 902       | 875     | 917      | 960      |
| Monthly Energy (GWh) | 507                          | 458      | 495    | 468    | 479    | 467    | 477    | 488    | 481       | 495     | 499      | 534      |
| Resource             |                              |          |        |        |        |        |        |        |           |         |          |          |
| Thermal (MW)         | 584                          | 584      | 584    | 584    | 584    | 584    | 584    | 584    | 584       | 584     | 584      | 584      |
| Hunters Point 2      | 0                            | 0        | 0      | 0      | 0      | 0      | 0      | 0      | 0         | 0       | 0        | 0        |
| Hunters Point 3      | 0                            | 0        | 0      | 0      | 0      | 0      | 0      | 0      | 0         | 0       | 0        | 0        |
| Hunters Point 4      | 163                          | 163      | 163    | 163    | 163    | 163    | 163    | 163    | 163       | 163     | 163      | 163      |
| Hunters Point GT1    | 52                           | 52       | 52     | 52     | 52     | 52     | 52     | 52     | 52        | 52      | 52       | 52       |
| Potrero 3            | 207                          | 207      | 207    | 207    | 207    | 207    | 207    | 207    | 207       | 207     | 207      | 207      |
| Potrero GT 4         | 54                           | 54       | 54     | 54     | 54     | 54     | 54     | 54     | 54        | 54      | 54       | 54       |
| Potrero GT 5         | 55                           | 55       | 55     | 55     | 55     | 55     | 55     | 55     | 55        | 55      | 55       | 55       |
| Potrero GT 6         | 53                           | 53       | 53     | 53     | 53     | 53     | 53     | 53     | 53        | 53      | 53       | 53       |
| Firm Import (MW)     |                              |          |        |        |        |        |        |        |           |         |          |          |
| BPA to BART          | 66                           | 66       | 66     | 66     | 66     | 66     | 66     | 66     | 66        | 66      | 66       | 66       |
| Total Resource (MW)  | 650                          | 650      | 650    | 650    | 650    | 650    | 650    | 650    | 650       | 650     | 650      | 650      |
| Reserves (MW)        | -246                         | -227     | -223   | -223   | -224   | -275   | -225   | -224   | -252      | -225    | -267     | -310     |
| Reserve Margin (%)   | -27.4%                       | -25.9%   | -25.5% | -25.5% | -25.6% | -29.7% | -25.7% | -25.6% | -27.9%    | -25.7%  | -29.1%   | -32.3%   |
| Import Capacity (MW) | 730                          | 730      | 730    | 730    | 730    | 730    | 730    | 730    | 730       | 730     | 730      | 730      |

In the early years of its analysis, Henwood only includes specific generation or transmission additions that are beyond the planning or development stage and actually in construction. For example, Mirant's proposed Potrero Unit 7 and other transmission improvement ideas have not been included. Small generating facilities that are primarily used to self-serve electric needs (with little left over for sale to the market) are not included in the load and resource balances in Tables 2-3 and 2-4.

## Modeling Electricity Operations of San Francisco and the WECC

Henwood followed its analysis of area capabilities and energy requirements with a simulation to forecast market clearing prices in the San Francisco area and to determine the level of imports required to be transported through transmission facilities into the San Francisco sub area.

The forecast of market clearing prices for individual markets within WECC was developed by conducting a simulation of the entire Western Interconnect system. This requires a vast amount of data regarding power plants, fuel prices, transmission capability and constraints, and customer demands.

Henwood utilizes its proprietary MARKETSYS data management system, in combination with its PROSYM production simulation model, to simulate the operation of the WECC. To characterize the WECC for the forecast, Henwood considers:

- Individual power plant characteristics, transmission line interconnections, ratings, losses, and wheeling rates;
- Forecasts of resource additions and fuel costs over time; and
- Forecasts of loads for each utility or load serving entity in the region.

With PROSYM, Henwood simulates the operation of the individual generators, utilities and control areas to meet the fluctuating loads within the region with hourly detail. The simulation takes into account various system and operational constraints, including a Monte Carlo methodology to incorporate individual unit planned and forced outages. Output from the simulation is generated in hourly, station-level detail and analyzed and these outputs were used within this study.

Henwood's price formation methodology combines information about the physical characteristics of the electric system in combination with reasonable assumptions about the behavior of various market participants to develop price forecasts. Two important non-physical market assumptions regard new generator entry behavior (that leads to long-term market equilibrium) and market participant bidding strategies.

The City of San Francisco was modeled in Henwood's topology as a separate liquid market so that the effects of transmission congestion on market clearing prices would be observed.

## WHOLESALE POWER MARKET COSTS AND RISKS

The load and resource balances shown in Tables 2-3 and 2-4 are interesting because they show a snapshot of area capability in the peak hour of the year. For example, the tables show that in the peak hour of 2003, San Francisco is expected to have a 960 MW peak load, with a total resource capability of 650 MW and a 730 MW total import capability. Just as instructive, however, is information on expected energy generation and imports by month and year to get a feel for the area's relative reliance on the two sources. Henwood's state-of-the-art simulation engine, PROSYM, would allow such an analysis on even an hourly basis. Table 2-5 provides annual "in area" generation and energy imports for the years 2003-2012 for Henwood's Base Case. Table 2-6 provides the same data by month for the year 2003.

**Table 2-5**  
**Annual San Francisco Generation and Imports – 2003-2012**  
**(GWh)**

| Year | Generation | Imports | Load  |
|------|------------|---------|-------|
| 2003 | 2,059      | 3,789   | 5,848 |
| 2004 | 2,091      | 3,838   | 5,929 |
| 2005 | 2,189      | 3,994   | 6,183 |
| 2006 | 2,241      | 4,069   | 6,309 |
| 2007 | 2,296      | 4,148   | 6,443 |
| 2008 | 2,348      | 4,223   | 6,571 |
| 2009 | 2,395      | 4,303   | 6,698 |
| 2010 | 2,416      | 4,334   | 6,751 |
| 2011 | 2,460      | 4,408   | 6,868 |
| 2012 | 2,508      | 4,481   | 6,990 |

**Table 2-6**  
**Monthly San Francisco Generation and Imports – 2003**  
**(GWh)**

| Month     | Generation | Imports | Load  |
|-----------|------------|---------|-------|
| January   | 181        | 326     | 507   |
| February  | 162        | 296     | 458   |
| March     | 174        | 320     | 495   |
| April     | 164        | 304     | 468   |
| May       | 167        | 312     | 479   |
| June      | 163        | 304     | 467   |
| July      | 167        | 310     | 477   |
| August    | 172        | 315     | 488   |
| September | 169        | 312     | 481   |
| October   | 174        | 321     | 495   |
| November  | 174        | 324     | 499   |
| December  | 190        | 344     | 534   |
| Total     | 2,059      | 3,789   | 5,848 |

## San Francisco Wholesale Power Costs

Henwood has prepared estimates of wholesale power market costs for the City of San Francisco in the future based on three potential supply portfolio scenarios:

1. Rely on the Spot Market – where it is assumed the City will rely exclusively on the spot market to fulfill its demand requirements.
2. Contract and Spot Mix - envisions reliance on a combination of long-term bilateral purchases and the spot market.
3. PG&E Supply - is based on a scenario where the City purchases energy at the forecasted tariffed rates of PG&E.

Wholesale power costs are presented in 2002 dollars and only consist of the generation cost component of electricity service. Costs related to transmission, distribution, or public purpose are not included in Henwood's estimates. In each of the following supply portfolios, the costs of energy are based on Henwood's hourly load forecast for the City for the years 2003 through 2012. Henwood included in its generation cost estimates a five percent adder per year for required ancillary services.

The five percent adder for ancillary services was developed based on Henwood's careful examination of the available historical data for the California ancillary service market to statistically estimate the relationship between electricity and ancillary service prices. Data for the January 1999-January 2001 were used for the analysis. Due to market turbulence in the first six months of the unregulated California market, as well as in the period following January 2001, these time periods were excluded.

### Rely on the Spot Market

Henwood has computed the City's wholesale generation component for this supply portfolio by assuming all power supplies are procured at Henwood's forecast of power market prices. Energy costs are calculated by multiplying the City's hourly load forecast by Henwood's hourly forecast of market clearing prices.

Scenarios provide a useful framework for thinking strategically about alternative views of the evolution of the markets and prices in the future. For purposes of the present study, three scenarios were created to estimate wholesale costs for the City, the Base Case, High Scenario, and Low Price Scenario.

1. Base Case – Henwood's current view of the market and it contains model assumptions that are consistent with Henwood's most up-to-date published WECC hourly pricing forecast (Henwood's Spring 2002 Update), including Henwood's most recent published forecast of gas prices.
2. High Price scenario – assumes that less generation will be built, gas prices will be higher, and there will be higher load growth in the WECC region. Henry Hub natural gas prices were increased by \$0.50 per MMBtu. Load forecasts were increased by 2.5 percent over the Base Case for all transmission areas. Certain

new generating plants not already under construction were delayed until market pricing dictated economic entry

3. Low Price Scenario – assumes the opposite conditions will prevail, *i.e.*, natural gas prices decrease by \$0.50 per MMBtu, loads decrease by 2.5 percent due to slower economic growth, and certain generating plants online dates were advanced.

Table 2-7 presents Henwood's forecast of annual average market clearing prices for the San Francisco area for these three cases. Henwood's generation cost calculation for this case does not include an estimate of the exit fee that will be charged to all PG&E customers that leave the system.

**Table 2-7**  
**Market Clearing Price Forecast – San Francisco**  
**(2002 \$/MWh)**

| Year | Market Clearing Price |               |              |
|------|-----------------------|---------------|--------------|
|      | Base Case             | High Scenario | Low Scenario |
| 2003 | 38.02                 | 43.84         | 30.16        |
| 2004 | 34.66                 | 40.66         | 28.89        |
| 2005 | 33.94                 | 39.96         | 28.07        |
| 2006 | 34.73                 | 40.80         | 28.65        |
| 2007 | 35.32                 | 41.65         | 29.11        |
| 2008 | 35.93                 | 42.31         | 29.70        |
| 2009 | 35.95                 | 42.41         | 29.81        |
| 2010 | 35.90                 | 42.26         | 29.94        |
| 2011 | 36.11                 | 42.42         | 30.31        |
| 2012 | 36.37                 | 42.52         | 30.66        |

Figure 2-8 graphically illustrates Henwood's Base, High and Low market price forecasts.

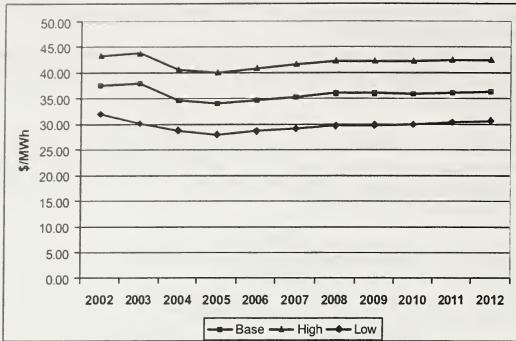


Figure 2-8: Market Clearing Price Forecast – San Francisco (2002 \$/MWh)

Table 2-8 below summarizes the Henwood’s generation cost estimate for the City of San Francisco for the years 2003-2012 with total reliance on the spot market under the three price scenarios.

**Table 2-8**  
**Generation Cost Component Forecast – San Francisco**  
**Rely on Spot Market Case**  
**(\$ 000)**

| Year | Base Case | High Scenario | Low Scenario |
|------|-----------|---------------|--------------|
| 2003 | 240,826   | 277,168       | 191,077      |
| 2004 | 222,925   | 261,433       | 185,729      |
| 2005 | 227,527   | 267,904       | 188,406      |
| 2006 | 237,664   | 279,114       | 196,331      |
| 2007 | 246,670   | 290,952       | 203,562      |
| 2008 | 255,730   | 301,336       | 211,852      |
| 2009 | 261,127   | 308,269       | 216,773      |
| 2010 | 262,707   | 309,200       | 219,317      |
| 2011 | 268,829   | 315,345       | 225,971      |
| 2012 | 275,598   | 321,524       | 232,789      |

## Contract and Spot Mix

Henwood has computed the City's wholesale generation component for this supply portfolio by assuming a portion of the power supplies is procured through long-term contracts and the balance is procured at Henwood's forecast of power market prices. The amount of power procured through long-term contracts is defined, in this case, as the difference between annual peak demand and area generation. The price for this power is based on Henwood's estimate of the fixed and variable costs for a new, combined-cycle generator starting commercial operation in 2003. Over the period 2003 through 2012, the amount of power procured under fixed, long-term contracts ranges from about 51% to 68% of the total load. The balance of the load is assumed procured from the spot market.

Table 2-9 below summarizes Henwood's generation cost estimate (in 2002\$) for the City of San Francisco for the years 2003-2012 with a combination of bilateral contract and spot market procurement under the base case scenario. . Henwood's generation cost calculation for this case does not include an estimate of the exit fee that will be charged to all PG&E customers that leave the system.

**Table 2-9**  
**Generation Cost Component Forecast – San Francisco**  
**Contract and Spot Mix Case**  
**(\$ 000)**

| Year | Base Case |
|------|-----------|
| 2003 | 254,897   |
| 2004 | 241,634   |
| 2005 | 246,275   |
| 2006 | 254,606   |
| 2007 | 262,110   |
| 2008 | 269,628   |
| 2009 | 275,883   |
| 2010 | 278,188   |
| 2011 | 284,942   |
| 2012 | 291,788   |

The amount of power procured under a bilateral contract varies over the years, as shown in Table 2-10 below.

**Table 2-10**  
**Bilateral Contract Capacity Forecast – San Francisco**  
**Contract and Spot Mix Case**

| Year | Bilateral Contract Capacity (MW) | Percent of Load served by Bilateral Contracts | Percent of Load served by Spot Market |
|------|----------------------------------|-----------------------------------------------|---------------------------------------|
| 2003 | 339                              | 51                                            | 49                                    |
| 2004 | 371                              | 55                                            | 45                                    |
| 2005 | 412                              | 58                                            | 42                                    |
| 2006 | 432                              | 60                                            | 40                                    |
| 2007 | 454                              | 62                                            | 38                                    |
| 2008 | 474                              | 63                                            | 37                                    |
| 2009 | 495                              | 65                                            | 35                                    |
| 2010 | 503                              | 65                                            | 35                                    |
| 2011 | 522                              | 67                                            | 33                                    |
| 2012 | 542                              | 68                                            | 32                                    |

Figure 2-9 below shows how this scenario would be represented in our modeling process for two, typical weekdays in August 2005.

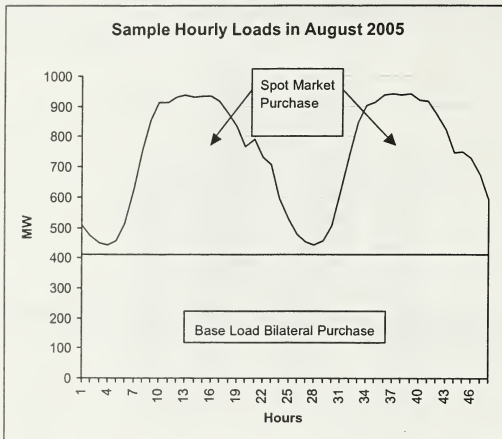


**Figure 2-9. Typical Weekday Loads in August 2005 – San Francisco, Contract and Spot Mix Case**

Combined cycle plants without any combustion turbines represent the most cost-effective bilateral purchase for this scenario, since the bilateral purchase can be base loaded (i.e., 7x24). If the magnitude of the bilateral purchase were to increase substantially, procurement of power from a peaking facility would become economic.

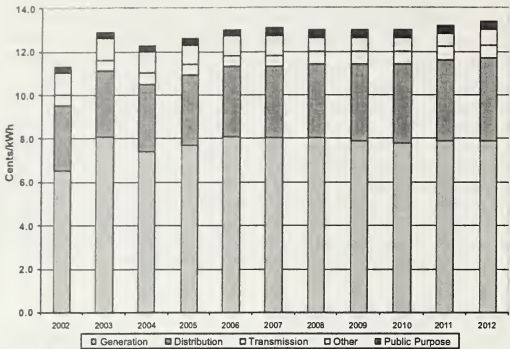
Although this scenario represents a simple approach to portfolio planning, it is nonetheless a start. For a comprehensive portfolio planning process, Henwood would capture the inherent risks in the market due to load volatility, market clearing price volatility, generation and transmission outage volatility, and fuel price volatility. Taking a stochastic approach, as Henwood has done for clients on numerous portfolio planning engagements, captures the risk and cost reduction that can be achieved from a combined portfolio of long-term, fixed price contracts, shorter-term contracts and spot market purchases. Thus, a portfolio that may appear more expensive than a 100% spot market purchase strategy may, in fact, be less expensive and reduce the volatility in the City's cost of power when viewed in a more realistic, stochastic assessment.

## **Remain as PG&E Customer**

Henwood developed a final scenario to explore the costs to the City of continuing to rely on PG&E and the CAIOS for electricity service. This estimate of the electricity costs for San Francisco customers is based on a forecast of tariff rates for PG&E.

The California Energy Commission has published a retail electricity price forecast in its 2002-2012 Electricity Outlook Report, published in February 2002. A utility's retail rates include the costs for generation of electricity, transmission, distribution, public purpose programs, the competition transition charge, nuclear decommissioning, ancillary services, and other miscellaneous charges. The forecast published in the CEC Outlook Report was prepared largely in November of 2001. Since then, the CPUC and CDWR have taken actions and rendered decisions that directly affect the CEC's forecast. In addition, the CEC's forecast included a rough estimate of the effects of the CDWR long-term energy contracts. The CEC analysis was performed before CDWR renegotiated a portion of the contracts as well.

Figure 2-10 shows the CEC's estimate of PG&E rate components in nominal dollars. Note that the CEC anticipates that generation costs will make up approximately 60 percent of PG&E's average electricity rates over the next decade.



Source: California Energy Commission 2002-2012 Electricity Outlook Report

Figure 2-11: CEC Forecast of PG&E Electricity Rate Components (\$Nominal)

Henwood used the CEC’s forecast of retail rates as a base estimate of generation costs and supplemented it with Henwood’s own estimates of generation costs related to the CDWR contracts, as recently amended.

To calculate the cost of CDWR contracts over the period 2003-2012, Henwood developed a coherent model of the California IOU system and CDWR’s future purchases and costs pursuant to ABX1 1. Figure 2-11 shows Henwood’s forecast of CDWR-related costs along with the CEC’s forecast of the other generation cost components.

# WHOLESALE POWER MARKET COSTS AND RISKS

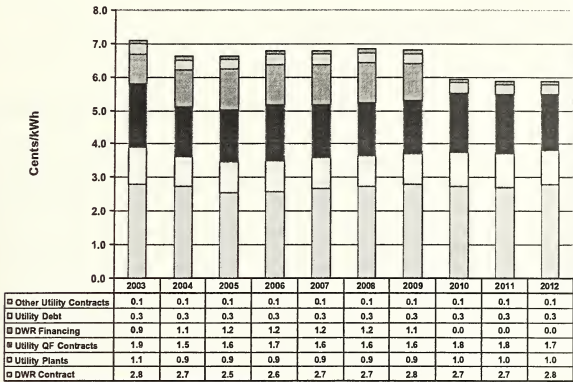


**Figure 2-12: CEC/Henwood Forecast of PG&E Generation Cost Components (\$Nominal)**

Table 2-11 below summarizes Henwood's generation cost estimate (in 2002\$) for the City of San Francisco for the years 2003-2012 if load were to continue to be served by PG&E.

**Table 2-13**  
**Generation Cost Component Forecast – San Francisco**  
**Remain as PG&E Customer Case**  
**(\$ 000)**

| Year | Base Case |
|------|-----------|
| 2003 | 404,263   |
| 2004 | 372,883   |
| 2005 | 380,713   |
| 2006 | 387,018   |
| 2007 | 385,347   |
| 2008 | 386,872   |
| 2009 | 382,916   |
| 2010 | 328,381   |
| 2011 | 323,406   |
| 2012 | 321,063   |



## Section 3

# TRANSMISSION ISSUES

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### General Discussion of Transmission

The delivery of electric energy is a complex integrated process from production to utilization. The previous section discussed issues surrounding the production process – i.e., generation. This section discusses the process of delivering power from large generating stations to local areas – i.e., transmission.

Once the transmitted power reaches the local area and the delivery voltage is reduced, we typically say that the distribution system starts. It is important to note that although the distinction between generation, transmission and distribution can be very important from the standpoint of control and pricing of electric energy, the delineations are often imprecise. The distinction between production of electric energy (generation) versus the transportation of energy (transmission and distribution) is easier to delineate because of the distinct difference in physical process. The production process changes energy in one form to electricity. But the delineation between transmission and distribution does not have a clear-cut physical distinction. Very often, transmission is distinguished from distribution by the voltage level of the electrical equipment. Also, delivery on an interconnected network of lines is more characteristic of transmission; whereas delivery on radial lines is associated with distribution. There are, however, exceptions to these guidelines. For example, PG&E serves the downtown area of San Francisco on a highly meshed network that is considered to be distribution, whereas radial lines that are considered to be transmission serve much of PG&E's rural areas in other parts of the State. SCE's bulk delivery system below 230kv is termed distribution. Conversely, PG&E's extensive 115kv and 60kv delivery system is termed transmission. For the purpose of this report we will use the terminology as it is commonly applied to the PG&E system that supplies San Francisco load, that is, 60 kV and above is typically transmission.

Prior to 1998, most transmission in California was operated by the three main investor-owned utilities: Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company. Beginning March 31, 1998 the California Independent System Operator (ISO) took over operational control of the transmission facilities owned by the three investor-owned utilities. The CAISO is a public benefit corporation created as a result of AB1890 and is responsible for maintaining the reliability of the ISO-controlled grid, serving most California consumers. "The core functions of the California are to:

- provide open and nondiscriminatory transmission service
- ensure safe and reliable operation of the grid
- Operate energy and reliability markets in a responsive, flexible and transparent manner

- Foster reasonable energy costs for California consumers<sup>8</sup>

Figure 3-1 shows the areas of California covered by the CAISO-controlled grid.

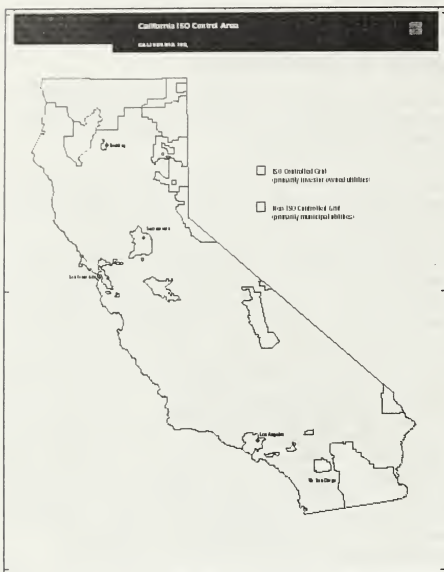


Figure 3-1: CAISO Control Area<sup>9</sup>

## Transmission Constraints

There are three major constraints to the physical delivery of electric power from other areas of the State to San Francisco. The first constraint involves a restriction on the amount of power that can be imported into the Greater Bay Area (GBA), a second constraint is a restriction on the amount of power that can be transmitted onto the Peninsula from the East Bay, and a third constraint is a restriction in the amount of power that can be imported to the northern Peninsula, including the City

<sup>8</sup> California ISO Website, [www.caiso.com](http://www.caiso.com)

<sup>9</sup> Ibid

## Greater Bay Area Constraints

There is insufficient transmission into the Bay Area to serve its load, so reliable electric service depends on power produced by local generators. The GBA transmission system consists primarily of four major outlying 500/230kv substations (PG&E's Vaca-Dixon, Tesla and Metcalf substations, and WAPA's Tracy substation) and a network of 230kv "import" circuits across the boundary. Potential failures at these outlying 500/230kv transformers and other GBA facilities, limit the amount of power that can be imported to reliably serve the Greater Bay Area. Twenty-one transmission lines cross the "cut plane" representing the Bay Area transmission system in Figure 3-2 and the loading on these lines is important in serving the Greater Bay Area reliably.

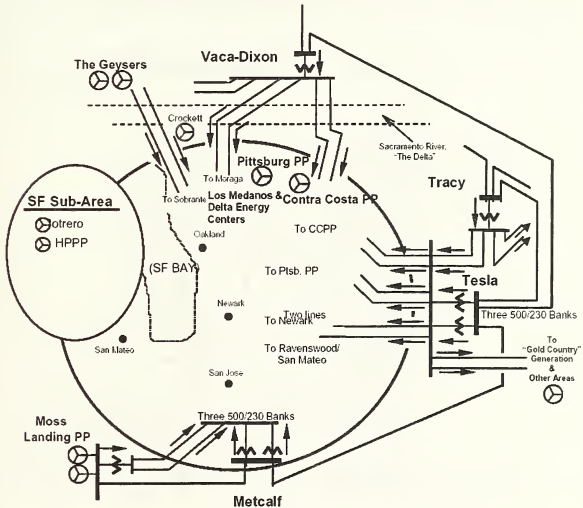


**Figure 3-2: Greater Bay Area Transmission System<sup>10</sup>**  
(Greater Bay Area is interior to the circle "cut plane")

From a transmission-planning standpoint, the GBA primarily consists of Alameda, Contra Costa, Santa Clara, San Mateo and San Francisco counties. In 2000, the GBA

<sup>10</sup> 2003 Reliability Must-Run Study Report, Appendix 5, May 2002

## Section 3

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exhibited a total simultaneous peak load of 8980 MW.<sup>11</sup> PG&E owns the majority of transmission and distribution facilities in the GBA. Three municipal electric utilities in the GBA own their own distribution systems: the Cities of Alameda, Palo Alto and Santa Clara. Additionally, some non-traditional municipal entities operate distribution systems to serve their own loads, including Hetch Hetchy, Stanford University and the University of California.

There are approximately 1,000 MW of regulatory Must-Take Qualifying Facility resources and self-generation in the Greater Bay Area that the CAISO assumes will be operating during the system peak. Table 3-1 is a listing of some generating plants in the Bay Area that must be operated to insure that the transmission lines into the Bay Area are not loaded above their rating. These units are considered by the CAISO to be "Effective Units" because their operation tends to relieve loadings on the critical transmission lines and/or transformer banks serving the Bay Area.

**Table 3-1**  
**2003 Greater Bay Area Generation Effective Units<sup>12</sup>**

| Name                         | MW          |
|------------------------------|-------------|
| Alameda                      | 50          |
| Contra Costa PP              | 680         |
| Delta Energy Center          | 975         |
| Santa Clara                  | 50          |
| Hunters Point PP             | 222         |
| IBM Cottle                   | 38          |
| Martinez Shell Refining Co.  | 100         |
| Oakland CT's                 | 165         |
| LMEC                         | 678         |
| Pittsburg PP                 | 2050        |
| Potrero PP                   | 366         |
| Tosco Union Ch               | 25          |
| J. Smurfit (Container Corp.) | 25          |
| Calpine Gilroy               | 135         |
| Valero                       | 100         |
| Moss Landing PP              | 2560        |
| <b>Total Available</b>       | <b>8219</b> |

The above table includes three new combined cycle generating plants: The Los Medanos Energy Center (LMEC), which already is on line; the Delta Energy Center (DEC), which is in the final stages of construction; and the expansion at the Moss Landing Power Plant, which also is in the final stages of construction.

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<sup>11</sup> 2003 Reliability Must-Run study Report, Appendix 5, May 2002

<sup>12</sup> Ibid

## Peninsula Sub-Area Constraints

Besides the constraints of getting the needed power into the Bay Area, there are two additional constraints to serving the load in the City of San Francisco. One results from the lack of transmission capacity into San Mateo substation. There are only two sets of 230kv transmission lines linking the San Mateo substation to the East Bay, one crossing the bay parallel to the San Mateo Bridge and one crossing the bay parallel to the Dumbarton Bridge. At least some of the generation within the Upper Peninsula (chiefly Hunter's Point and Potrero Power Plants) must be operated to prevent overloading these lines during peak loading conditions and contingency conditions. Currently, a more limiting condition exists north of San Mateo substation; to prevent overloading of transmission serving the Upper Peninsula and San Francisco at certain levels of load, a minimum level of generation must be operating at Hunter's Point and Potrero Power Plants.

Figure 3-3 is a schematic of the transmission lines terminating at San Mateo Substation and the 5-115kv overhead lines which transmit power to San Francisco from San Mateo.

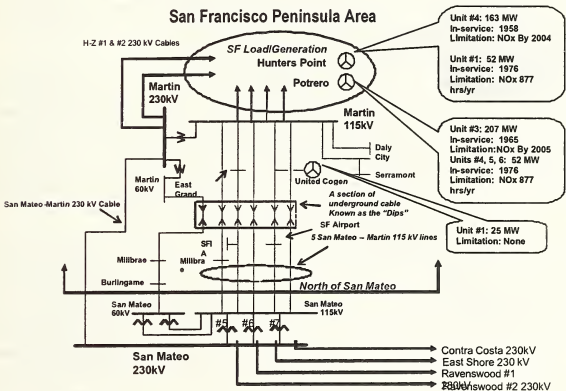


Figure 3-3: San Francisco Area Power System Diagram<sup>13</sup>

<sup>13</sup> Draft San Francisco Peninsula Long-Term Transmission Planning Study, Phase 2 Study Plan, Version 1.4, May 28, 2002.

## Transmission Service Reliability

Reliable service is very important to most electric customers. Although most customer outages are caused by deficiencies/outages of the distribution system, this section will focus on transmission system reliability. Though usually rarer than outages caused by a failure in the distribution system, outages caused by a failure in the transmission system tend to be of a larger scale and can lead to a complete shut down of a whole metropolitan area, such as occurred in San Francisco on December 12, 1998.

Transmission systems are designed so that for certain failures of components of the transmission system supplying an area that might occur at the same time as failures of the generation serving the same area, no interruption of service would be expected to occur. PG&E performs planning studies and develops a grid expansion plan to meet the CAISO Grid Planning Standards. These Planning Standards include separate guidelines for the Greater Bay Area and for the San Francisco Sub-area and include the Western Electricity Coordinating Council (WECC) Reliability Criteria. The CAISO Grid Planning Standards are contained in **Appendix A**. At the present time, the contingency during the 5-year CAISO planning horizon that is most limiting (i.e., creates the greatest need for the construction of new transmission lines into the City) is the overlapping outage of the underground 230 kV circuit from the San Mateo Substation to the Martin Substation, with Potrero Unit 3 and a one Combustion Turbine at either Hunter's Point or Potrero off line.

Substantial upgrades have been and are being made to the transmission system into the Bay Area including a new 230kv line from Tesla to Newark and new 525/230kv transformer banks at Tesla, Tracy and Metcalf Substations. The current system can supply about 10,500 megawatts of load, but is dependent upon the operation of many older Bay Area generating units which often have been unavailable during peak times when they are needed the most. A major contributing factor to the rolling blackouts in the Bay Area on June 14, 2000, was the inability of the existing Bay Area transmission and generation to provide adequate voltage support at Newark Substation.

PG&E is studying the potential for a series of new 525kv and 230kv lines and a new 525/230kv substation near Sunol to raise the load serving capability of the transmission system into the Bay Area. Assuming the existing generation is maintained and is supplemented with some new generation additions, the Bay Area transmission load serving capability could be increased by 2300 MW, from the current 10,500 MW to 12,800 MW. To meet the CAISO Planning Criteria, this plan likely would be implemented incrementally, and would continue to require maximum reliance on local generation. As an alternative to taking an incremental approach to meeting the CAISO Planning Criteria, PG&E is performing, with review by the Cities of San Francisco and Palo Alto; economic studies to determine if accelerating these contemplated additions would be economically justified. These studies will consider the economic benefits of reducing the "extra costs" incurred due to the need to operate more expensive Bay Area generation during times of transmission congestion and payments to local generators made under Reliability Must Run contracts. The studies potentially also will consider the economic benefits of reduced outage costs to customers resulting from transmission additions.

The loss of the 115kv bus at San Mateo Substation on December 8, 1998, which resulted in the widespread outage of the City is an example of an outage risk that could be reduced if additional transmission were developed based on economic benefits. Following the outage, in April 1999 the CAISO formed a study group to evaluate the long-term power supply adequacy for serving San Francisco. The result of that study has been the decision to build a 230kv line from Jefferson Substation in Redwood City to Martin Substation near San Francisco by 2005. Figure 3-4 shows the existing and proposed transmission linking the Peninsula to the East Bay.

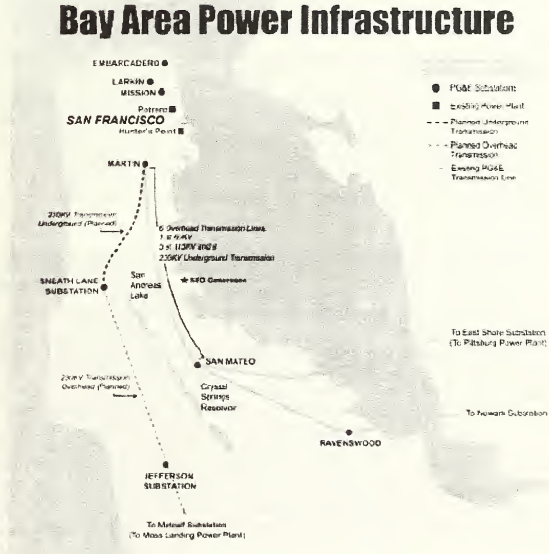


Figure 3-4: Peninsula Transmission Links<sup>14</sup>

## Reliability Impacts of Generation Outages

An integral part of providing reliable service to the City's electric customers is the existing generation at Hunter's Point and Potrero Power Plants. Both Hunter's Point

<sup>14</sup> The Electricity Resource Plan, Choosing San Francisco's Future, March 2002

and Potrero are old, unreliable plants, and the City has been notified by the CAISO on numerous occasions to be ready to shed load because of conditions caused by the failure or repair of one or more of these generating units. Table 3-2 lists the age, capability and operating limitations of these plants.

[NOTE: the format of the first entry on the table is shifted in the original report. Need to try to fix this]

Table 3-2<sup>15</sup>  
Power Generation on the San Francisco Peninsula

| Power Generation on the San Francisco Peninsula |      |      |             |                 |                        |
|-------------------------------------------------|------|------|-------------|-----------------|------------------------|
| Plant                                           | Unit | Size | Fuel Type   | In-Service Date | Operating Restrictions |
| Potrero                                         |      | 3    | 207         | Natural Gas     | 1965                   |
| Restrictions                                    |      |      |             |                 | N0x                    |
|                                                 | 4    | 52   | Distillate  | 1976            | 877 hours/year         |
|                                                 | 5    | 52   | Distillate  | 1976            | 877 hours/year         |
|                                                 | 6    | 52   | Distillate  | 1976            | 877 hours/year         |
| Hunter's Point                                  | 1    | 52   | Distillate  | 1976            | 877 hours/year         |
|                                                 | 4    | 16.3 | Natural Gas | 1958            | N0x restrictions       |
| United Cogen (at SFO)                           | 1    | 20   | Natural Gas | 1986            | None                   |

Source: PG&E

An inherent limitation of the CAISO Planning Criteria is that they are deterministic. For example, they do not take into account the reliability of individual generating units, which is typically inversely related to the age of the units. A study by the California Energy Commission (Electricity Outlook for 2002-2012) used an internally developed model (the Supply Assessment Model) and historical plant outage data to estimate the likelihood of peak hour electric service demand reductions for various regions in the State. Table 3-3 shows that even though all of the areas within the State must meet the CAISO Planning Criteria, some areas are much more likely to experience load shedding at the time of an area's peak load. The three areas with the greatest risk of demand reductions (San Francisco, San Diego and Imperial Irrigation District) share the common characteristics that they depend on old and unreliable generation and on limited transmission to meet their needs. To bring the risk of outages in San Francisco in line with other areas in the State will require installation of newer, more reliable generation and increased transmission into San Francisco.

<sup>15</sup> Ibid

**Table 3-3**  
**Demand Reduction Uncertainties<sup>16</sup>**

**Demand Reduction Uncertainties**  
**Shortage Risks and Maximum Deficits by Transmission Zone**  
**Summer Peak Period 2003**

| Transmission Zones | Risks (Percent)   |                    | Maximum Deficit (MW) |                    |
|--------------------|-------------------|--------------------|----------------------|--------------------|
|                    | Baseline Scenario | High Load Scenario | Baseline Scenario    | High Load Scenario |
| South CA           | 1.3               | 4.3                | 1,730                | 5,210              |
| North CA           | 0                 | 0                  | 0                    | 0                  |
| San Diego          | 7                 | 17                 | 3,030                | 3,540              |
| San Francisco      | 13.7              | 11                 | 230                  | 210                |
| IID                | 7.3               | 18.3               | 280                  | 310                |
| LADWP              | 0                 | 0                  | 0                    | 0                  |
| SMUD               | 0                 | 0                  | 0                    | 0                  |
| CCENT              | 0                 | 0                  | 0                    | 0                  |

## Reliability Impacts of Local Generation and the San Francisco Energy Plan

In July of 1998 San Francisco signed an agreement with PG&E to close Hunter's Point Power Plant when it is no longer needed to provide electric reliability in San Francisco. PG&E, with CAISO concurrence, has shut down the two oldest units at Hunter's Point (Units 2 and 3) and converted them to synchronous condensers. When the CAISO Board of Governors in May 2002 approved the Jefferson-Martin transmission project 2002, the City requested that the Board also approve the shut down of Hunter's Point Power Plant. The Board did not act on the City's request, but directed staff to "work with the City of San Francisco and interested stakeholder groups toward their goal of closing the Hunter's Point Power Plant." As part of implementing this directive, the CAISO is sponsoring Phase 2 of the San Francisco Peninsula Long Term Transmission Planning study to develop a long-term load-serving plan that is responsive to varying levels of load growth and generation development and retirement. The Draft Phase 2 Study Plan is included in **Appendix B**.

Mirant Corporation has proposed building a 540mw combined cycle power plant (Potrero Unit 7) next to their existing Potrero Power Plant. To improve the reliability of the proposed plant, the CAISO and CEC are considering requiring changes to the plant design to eliminate potential common mode failures that could trip the entire plant off line. The CEC staff, in February 2002, released its final staff assessment on

<sup>16</sup> 2002-2012 Electricity Outlook, California Energy Commission, February 2002

Potrero Unit 7, and recommending that the plant be licensed with certain mitigation measures. Two key mitigation measures are replacing the proposed once-through cooling system to reduce harmful impacts on the bay marine environment, and local mitigation of particulate emissions.

In March 2002, San Francisco's Department of the Environment and the Public Utilities Commission jointly published "The Electricity Resource Plan, Choosing San Francisco's Energy Future" ("Energy Plan"). The Energy Plan recommends that the City intervene in the CEC licensing process to ensure that the environmental impacts of the proposed Potrero Unit 7 are minimized. The Energy Plan also recommends the City oppose Potrero Unit 7 unless the plant is re-configured to ensure the prompt closure of both the Hunter's Point Power Plant and Potrero Unit 3. The Energy Plan also proposes that the City identify at least three locations to build City-owned cogeneration or small combined cycle power plants, and recommends identifying specific sites for various private sector sponsored distributed generation applications. A key recommendation of the Energy Plan is the aggressive pursuit of energy efficiency projects and identification of locations for the installation of solar and other small-scale renewable energy systems in the City.

Describing the relative reliability impacts of the various elements of the Energy Plan is beyond the scope of this report. It is clear, however, that:

- Adding transmission will increase reliability even without new generation additions;
- Adding local generation will increase reliability
- Replacing existing local generation with new local generation can increase reliability due to the lower forced outage rate of new generation plants
- Reducing load through conservation increases reliability

## Transmission Service Pricing

In the current electric market structure, electricity is delivered to both retail and wholesale customers over the PG&E transmission system. The Federal Energy Regulatory Commission approves the transmission rates for both sets of customers. These rates cover operations and maintenance costs, as well as recovery of the capital cost of the transmission system, including an authorized rate of return on investment. Transmission charges for retail customers are included in the bundled retail electric tariffs approved by the California Public Utilities Commission. Although PG&E's costs to provide transmission service vary by geographical location, PG&E's current method of recovering these costs (as authorized by the CPUC) does not take into account these geographical differences. For example, in general the capital, operations and maintenance costs related to providing transmission service to rural customers is greater than those for urban customers. Conversely, due to the transmission constraints into the Bay Area, the costs to deliver energy to the Bay Area customers tends to be higher than for customers in other parts of PG&E's service area.

At the wholesale level, the City's cost of using PG&E's transmission system to serve Municipal Loads, mostly to deliver power generated at Hetch Hetchy's hydroelectric facilities, is determined by rate schedules in its current Agreement with PG&E. Changes to these rates must be filed by PG&E and approved by the Federal Energy Regulatory Commission. To date, the City and other entities with existing transmission contracts with PG&E that are FERC jurisdictional have been successful in resisting major transmission rate increases. Upon termination of the Agreement, or if the City decides to use its own transmission facilities to serve retail customers, there are two main transmission service options: CAISO Transmission Service and Separate Control Area Service.

## **CAISO Transmission Service**

In this section, we will describe the current structure and pricing of CAISO transmission service and proposed pricing changes associated with the ISO's Comprehensive Market Design proposal filed at FERC May 1, 2002.

The CAISO provides network, rather than point-to-point transmission service. This means that CAISO customers can use the CAISO grid to deliver energy from anywhere on the grid to their load, without having to link together a series of transmission paths. The costs of CAISO transmission service are grouped into three broad categories:

- Transmission Access Charges
- Grid Management Charges
- Transmission Congestion Charges

Transmission Access Charges predominately recover the capital and fixed operating costs of the grid. Grid Management Charges recover the ISO's administrative and overhead costs associated with providing various grid services. Transmission Congestion Charges are used to recover out of merit order generation costs and to allocate scarce transmission on constrained interfaces.

### **Transmission Access Charges**

The ISO's access charge costs were "utility specific" at the start of the CAISO and are gradually changing to a common CAISO grid-wide charge. Beginning in 2001, when the City of Vernon joined the three main Investor-owned utilities as an CAISO Participating Transmission Owner (PTO), the utility specific access fees were changed into area-specific transmission access charges (TAC). The City of San Francisco is in the Northern California TAC area, which at the present time correlates to the PG&E system. If other entities such as SMUD, Palo Alto, Santa Clara, Alameda or other NCPA cities should become Participating Transmission Owners, control of their transmission would be assumed by the ISO, and their transmission costs would be included in the Northern TAC area.

The Transmission Access Charge is broken into two components: a High Voltage access charge for use of the 230kv and above network, and an additional Low Voltage

access charge for those customers that also use the lower voltage transmission facilities. The access charge methodology currently is under review by FERC, and the rates being charged today are subject to refund pending a FERC decision. The high voltage access charge is weighted 80% to pay for TAC area costs and 20% to pay for statewide costs. Assuming the filed tariff is approved by FERC and no future changes are made to its basic structure, the statewide portion of the High Voltage Charge will be increased each year by 10%, with a corresponding 10% decrease in the TAC area portion. Therefore, by 2010, everyone taking CAISO service would pay the same ("postage stamp") access fee for High Voltage service.

Most customers in Northern California take low voltage transmission service (below 230kV), the charges for which are recovered on a utility specific basis. For example, PG&E customers in San Francisco pay both the High and Low Voltage component of the access fee applicable for Northern California because San Francisco loads are served from PG&E's low voltage transmission system. FERC is expected to issue a Notice of Proposed Rule making this summer to develop an industry-wide Standard Market Design, which may change the methodology for recovering transmission access costs.

Table 3-4 below shows the current PG&E High Voltage and Low Voltage access charges.

Table 3-4<sup>17</sup>  
Wheeling Access Charges

Wheeling Access Charge for PG&E Take Out Points Interconnecting Non-PTOs Within ISO Control Area to the ISO Controlled Grid

| PTO  | HV Wheeling Access Rate (\$/MWh) | LV Wheeling Access Rate (\$/MWh) | Effective Dates     |
|------|----------------------------------|----------------------------------|---------------------|
| PG&E | 2.28                             | 3.3678                           | 1/1/2002 – 12/31/02 |

Grid Management Charges

The CAISO recovers its administrative, financing and overhead costs of providing various grid services using a Grid Management Charge (GMC). The GMC is unbundled into three charge types:

- Control Area Services
- Congestion Management
- Market Operations/Ancillary Services and Real Time Energy Operations

The Control Area Services charge recovers the ISO's cost of ensuring safe, reliable operation of the grid and dispatch of bulk power. This charge is applied to CAISO metered load and exports, and currently is \$0.58/MWh.

<sup>17</sup> Wheeling Access Charges 2002, California ISO

The Congestion Management Charge recovers the ISO's costs of operating the congestion management process, firm transmission rights auction and monitoring. This charge is applied to net scheduled inter-zonal flow, and currently is \$0.37/MWh.

The Market Operations Charge/Ancillary Services and Real Time Operations (ASREO) charge recovers the ISO's costs of market and settlement related services. This charge is applied based on total purchases and sales of ancillary services capacity, Supplemental Energy and Imbalance Energy, and currently is \$0.96/MWh. It is applied to 50% of self-provided Ancillary Services capacity.

The ISO's grid management charges are significantly higher than charges for similar services provided by other independent system operators, and can be a significant cost for CAISO participants. The GMC costs are embedded in the PG&E retail tariffs for the City's residents and businesses served by PG&E. Under its Agreement with the City, PG&E could attempt to pass these costs on to the City's Municipal Loads, but to date has not done so. Should the City take CAISO service in the future for its Municipal Loads, or for direct sales to retail customers, it would be exposed to these GMC costs.

### **Transmission Congestion Charges**

The CAISO has two types of Transmission Congestion Charges:

- Intra-zonal congestion charges
- Inter-zonal congestion charges

Intra-zonal congestion charges recover the cost of redispatching higher cost generation within a broader congestion zone during periods when the import capabilities of the lines into the zone would be exceeded. These intra-zonal costs currently are charged as an uplift to the customers within the zone in which they are incurred. If the amount of intra-zonal congestion reaches a significant level, a process exists for creating a new transmission zone.

Inter-zonal congestion charges are the means by which the CAISO allocates limited transmission capacity on lines between zones when the requests for usage exceeds the rated limits of the lines. Figure 3-5 depicts the ISO's Network Model and shows the linkages between each of the three active transmission zones (NP15, ZP26 and SP15) and other areas outside of the CAISO grid. Separate transmission zones have been defined for areas which are expected to experience a significant amount of inter-zonal congestion between the zones. Note that San Francisco and Humboldt are designated inactive zones by the CAISO Board of Governors on an interim basis, at least until such time that the CAISO determines the criteria for defining "workably competitive generation markets."

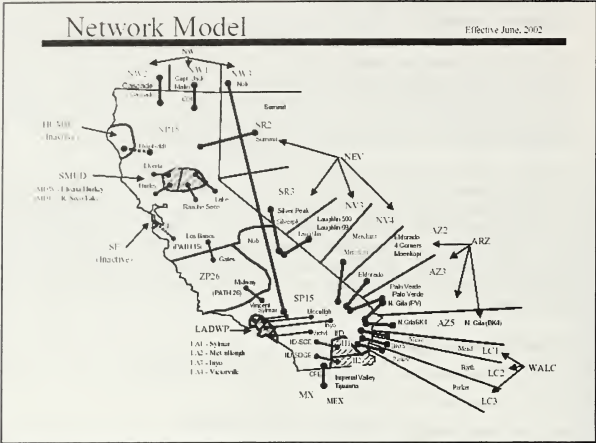


Figure 3-5: CAISO Network Model<sup>18</sup>

Under the current CAISO pricing system, Inter-zonal Congestion Charges are applied to deliveries using the CAISO grid into or out of each of the three active zones (NP15, ZP26, SP15) during periods when requests to schedule deliveries between the zones exceed the capability of the lines. The amount of Inter-zonal Congestion Charges is essentially the difference in market price of electricity between the zones. The imposition of these charges and the allocation of the revenues from them can have a large impact on the cost of power for all electric customers located in the City of San Francisco, and will be an important consideration in the exploration of alternative methods of City involvement in the provision of electric service to its consumers.

The Inter-zonal Congestion Charge revenues are allocated to the Transmission Owners, or to parties that have purchased Firm Transmission Rights (FTRs) for the constrained path from the Transmission Owner in an auction. The revenues from the FTR auction are used to reduce the Transmission Access Charges for all of each Transmission Owners' customers in future years. An undesirable result of this procedure is that during times of transmission constraints, consumers in constrained zones do not get the benefit of the lower cost electricity that is being imported on the lines. The City has been a vigilant critic of the inequities and perverse incentives inherent in this system. As a result of the City's efforts, San Francisco was declared

<sup>18</sup> California ISO

an “inactive” zone, and the adverse impacts of this system on electric consumers in the City have been avoided to date.

Unfortunately, San Francisco is exposed to changes in the above situation. The existing CAISO Tariff allows for the creation of new active zones and a proposal to create 15 local pricing areas (i.e., zones) was developed, but not adopted, in 2000. The latest threat, which appears likely to proceed because it has substantial stakeholder support and is consistent with proposed FERC policy, could create individual prices for all the approximately 3000 buses or “nodes” in the transmission network. This threat is one of the key elements of the ISO’s Comprehensive Market Design filing with FERC on May 1, 2002.

## Comprehensive Market Design Filing

On May 1, 2002, the CAISO submitted a major filing to FERC which could have a significant impact on the cost of delivered energy to the City. In its motion to intervene and protest the ISO’s Comprehensive Market Design filing, the City notes that:

“The ISO’s MD02 Filing proposes to change the energy, capacity and transmission service pricing currently charged to San Francisco customers in ways that will shift significant costs currently shared by all users of the grid or all transmission customers in the former PG&E service territory directly to those customers located in San Francisco. The impact of the proposed Capacity Availability obligation (“ACAP”), the locational ACAP requirement, the transfer of current Reliability Must-Run (“RMR”) procurement responsibility from all CAISO grid users to the local loads closest to the RMR unit, the exposure of load to locational pricing, the adequacy of Firm Transmission Rights (“FTRs”) as a hedge against increased congestion costs due to Locational Marginal Pricing (“LMP”) and other transmission and resource procurement issues affect San Francisco directly.”<sup>19</sup>

Three elements of the CAISO filing that could influence the City’s options for providing electric services are:

- Redesign of the ISO’s congestion management, energy and ancillary services markets based on Locational Marginal Pricing (LMP)
- A locational capacity obligation on Load Serving Entities
- Increased CAISO commitment to transmission expansion to remove constraints.

## Locational Marginal Pricing

The CAISO is proposing to move from the current three zone congestion management model to a model that produces locational marginal pricing at the nodal level, using an optimal power flow algorithm and full network model to adjust generation and load

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<sup>19</sup> Motion to Intervene and Protest of the City and County of San Francisco (see Appendix C)

## Section 3

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schedules. This means that for each scheduling period (i.e. 10-minute interval), there potentially could be approximately 3,000 different prices for energy within the CAISO grid. This approach would eliminate the distinction between intra-zonal and inter-zonal congestion. The CAISO believes this approach will lead to more efficient use of the grid and reduce operational problems created by infeasible schedules which currently are allowed in the zonal model.

To simplify scheduling and settlements, the CAISO is proposing to use Load Aggregations so customers served by some Load Serving Entities likely would see prices similar to the existing zonal prices. For example, Table 3-5 shows that San Francisco is included in the PGE3 Load Aggregation, which covers most of the load included in the current NP15 zone. This means that intra-zonal congestion costs that are spread as an uplift to all NP15 loads in the current zonal model would be spread to a slightly less broad aggregation of customers – those in PGE3. The proposal envisions disaggregating pricing to the Load Group level, but has not disclosed the criteria or timing for doing so. The City therefore could be at risk to being exposed both to higher Bay Area energy prices (if a Bay Area Load Aggregation is created), and to even higher prices at the San Francisco Load Group level.

**Table 3-5<sup>20</sup>**  
**Initial Definition of Standard Load Aggregations**

Initial Definition of Standard Load Aggregations  
 (Work in Progress)

| Trans-<br>mission<br>Area | Trading<br>Hub | Load Aggregation |           | Name and<br>Correspondence to Existing Load Groups <sup>57</sup>                                         |
|---------------------------|----------------|------------------|-----------|----------------------------------------------------------------------------------------------------------|
| PG&E                      | NP15           | PGE3             | PGHB      | Humboldt (PG&E Humboldt/ PGHB) (current PGE 1 demand zone)                                               |
|                           |                |                  | PGSF      | San Francisco (PG&E San Francisco/ PGSF and PG&E Peninsula North/ PGP 1) (current PGE 2 demand zone)     |
|                           |                |                  | PGDI      | Diablo (PG&E Diablo/ PGDI)                                                                               |
|                           |                |                  | PGEB      | East Bay (PG&E East Bay/ PGEB)                                                                           |
|                           |                |                  | PGMS      | Mission (PG&E Mission/ PGMS)                                                                             |
|                           |                |                  | PGSJ      | San Jose/ Peninsula (PG&E De Anza/ PGDA, PG&E Peninsula South/ PGP 2, and PG&E San Jose/ PGSJ)           |
|                           |                |                  | PGF1      | Fresno (PG&E Fresno North/ PGF1, and part of PG&E Yosemite/ PGYO)                                        |
|                           |                |                  | PGNC      | North Coast (North Bay LPA portion of PG&E North Coast/ PGNC)                                            |
|                           |                |                  | PGFG      | Fulton Geysers (Fulton Geysers LPA portion of PG&E North Coast/ PGNC)                                    |
|                           |                |                  | PGBC      | Battle Creek LRA (RMR area in PG&E North Valley/ PGNV)                                                   |
|                           |                |                  | PGSI      | Sierra LRA (RMR area in PG&E Sierra/ PGSI and parts of PG&E Sacramento/ PGSA)                            |
|                           |                |                  | PGST      | Stockton LRA (RMR area in PG&E Stockton/ PGST and Stanislaus/ PGSN)                                      |
|                           |                |                  | PGNB      | North Bay (PG&E North Bay/ PGNB, and remaining portion of PG&E North Coast/ PGNC)                        |
|                           |                |                  | PGNV      | North Valley (remaining portion of PG&E North Valley/ PGNV)                                              |
|                           |                |                  | PGSA      | Sacramento Valley (remaining portions of PG&E Sacramento/ PGSA and Sierra/ PGSI)                         |
|                           |                |                  | PGSN      | San Joaquin (remaining portions of PG&E Stockton/ PGST, PG&E Stanislaus/ PGST, and PG&E Yosemite/ PGYO)  |
|                           |                |                  | PGCC      | Central Coast (PG&E Central Coast/ PGCC)                                                                 |
|                           |                |                  | CT1       | California Oregon Transmission Project                                                                   |
|                           |                |                  | CSF1      | City of San Francisco                                                                                    |
|                           |                | CWR1             | CWR1      | California Dept. Of Water Resources                                                                      |
|                           |                |                  | CWR4      | California Dept. Of Water Resources                                                                      |
|                           |                | LMD1             | LMD1      | Lassen Municipal Utility District                                                                        |
|                           |                | MID1             | MID1      | Modesto Irrigation District                                                                              |
|                           |                | NCP1             | NCP1      | Northern California Power Agency (includes City of Santa Clara)                                          |
|                           |                | RED1             | RED1      | City of Redding                                                                                          |
|                           |                | SMD1             | SMD1      | Sacramento Municipal Utility District                                                                    |
|                           |                | TID1             | TID1      | Turlock Irrigation District                                                                              |
|                           |                | WAP1             | WAP1      | Western Area Power Administration                                                                        |
|                           | ZP26           | PGE4             | PGLP      | Los Padres (PG&E Fresno South/ PGF2, PG&E Kern/ PGKE, and PG&E Los Padres/ PGLP)                         |
|                           |                |                  | CWR2      | California Dept. of Water Resources                                                                      |
|                           |                | CWR2             | CWR5      | California Dept. of Water Resources                                                                      |
|                           |                |                  | NCP2      | Northern California Power Agency                                                                         |
| SCE                       | SP15           | SCE1             | SCSO      | L.A./ Orange County (SCE South/ SCSSO)                                                                   |
|                           |                |                  | SCEA      | Other SCE (SCE East/ SCEA, SCE High Desert/ SCHD, SCE North/ SCNO, SCE Sylmar/ SCDC, and SCE West/ SCWE) |
|                           |                | ANA1             | ANA1      | City of Anaheim                                                                                          |
|                           |                | CWR3             | CWR3      | California Dept. of Water Resources                                                                      |
|                           |                |                  | CWR6      | California Dept. of Water Resources                                                                      |
|                           |                | PAS1             | PAS1      | City of Pasadena                                                                                         |
|                           |                | RVD1             | RVD1      | City of Riverside                                                                                        |
|                           |                | VRN1             | VRN1      | City of Vernon                                                                                           |
|                           |                | Other ...        | Other ... | Load Groups for other municipal utilities?                                                               |
|                           |                | SDG1             | SDG1      | San Diego Gas and Electric                                                                               |

In addition to concerns about exposure to higher Bay Area and Peninsula energy prices, the City is concerned that in a nodal model, the impact on consumers of potential market power abuse by generators will be very concentrated. The CAISO

<sup>20</sup> California ISO Comprehensive Market Design Proposal, May 1, 2002 FERC Filing

has proposed local market power mitigation measures, but these might be insufficient to fully address this exposure.

Finally, it is worth noting that most power is expected to be procured in bilateral, forward market transactions outside of the ISO's markets. Because PG&E is the Load Serving Entity currently serving most City consumers, the California Public Utilities Commission's approach for allocating PG&E's energy procurement costs will have a large impact on the electric costs for the City's consumers.

### **Locational Capacity Obligation on Load Serving Entities**

The CAISO is proposing that Load Serving Entities would have an obligation to provide capacity in excess of their forecast needs to support the reliable operation of the grid. The LSE would have to use a combination of firm transmission rights and local generation to meet this obligation. The CAISO also is proposing to transition the current Reliability Must Run resource obligations to the local LSEs.

This proposal exposes all CAISO grid consumers to potentially higher costs due to the need to procure excess capacity. Further, consumers located in transmission constrained areas, such as San Francisco, would not be able to rely on transmission to import capacity to meet all of the capacity obligation. If the locational capacity obligation is imposed without allowing a transition period sufficient to develop new local generation, transmission, demand management and conservation projects, the City potentially would be in a difficult position in negotiating with only a handful of local generation owners. The CAISO is hoping to eliminate the need for "Condition 1" RMR units (the RMR units in San Francisco are "Condition 2" units) by 2006 by expanding the transmission grid in constrained areas. The CAISO also would like to develop a form of cost-based locational capacity contract to mitigate against the exercise of market power.

The locational capacity obligation should make local conservation programs, distributed generation and transmission projects more attractive.

PG&E's allocation of costs for a locational capacity obligation will be determined by the CPUC. The cost allocation actions of the CPUC will impact the transmission and retail services options available to the City.

### **Increased CAISO Commitment to Transmission Expansion**

The CAISO recognizes the potential for severe cost impacts on consumers in congested areas due to constraints in a transmission system that was designed and built under an entirely different regulatory regime, one which did not anticipate competitive generation markets and locational pricing. The CAISO therefore has stated that it will attempt to address in a realistic manner the question of how to upgrade transmission into congested areas to enable consumers in these areas to enjoy the benefits of competitive energy markets.<sup>21</sup>

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<sup>21</sup> Ibid

An important element of this renewed commitment is the ISO's efforts to develop a methodology for evaluating economically-driven transmission projects (as opposed to reliability-driven projects). This methodology could lead to the development of Bay Area transmission projects that might not be needed strictly to meet reliability criteria, but that could lower costs for consumers. It will be important for the City to participate in the development and implementation of this methodology, and in FERC proceedings regarding cost allocation.

The ISO's stated commitment in the CMD filing to expanding the transmission grid to remove constraints is a step in the right direction, but needs further development. In particular,

- the CAISO does not have the authority to construct or finance facilities
- the CAISO has a limited ability to cause construction of facilities
- the CAISO has no ability to enforce construction "orders"
- PG&E's bankruptcy clouds the ISO's ability to cause facilities to be built.

Nonetheless, if the CAISO can somehow accomplish the above, it could lead to construction of needed facilities in the Bay Area to improve reliability and reduce exposure to high-priced local generation.

## **Transmission Service Local Control**

Historically, the City has had limited ability to control the development and operation of the transmission grid serving San Francisco. PG&E, as the Transmission Owner serving most of Northern California, is responsible for maintaining and developing the transmission system serving the Bay Area. The CAISO is responsible for operating the system. Prior to 1998, PG&E's transmission and generation were operated in an integrated fashion. Due to the high cost and difficulty of siting new transmission, PG&E chose to operate certain generation facilities out of merit order rather than to build more transmission facilities. In the current zonal market structure, and in the proposed nodal market structure, it is more important than ever to ensure that sufficient transmission facilities are available to meet market needs. In its Comprehensive Market Design filing, the CAISO has proposed regulatory measures to give it greater control over the dispatch and pricing of generation facilities, both to ensure reliable operations and to reduce the risk of generators exercising market power. These regulatory measures cannot provide the same reliability and market power mitigation benefits that can be achieved by expanding the amount of transmission into and within the Bay Area.

Until recently, PG&E has been reluctant to invest in significant upgrades to its transmission system. For example, PG&E has resisted upgrading a major link between Northern and Southern California, Path 15, that often is fully loaded, particularly in the south-to-north direction during off-peak and winter hours. PG&E was ordered by the CPUC to submit an application for a Certificate of Public Convenience and Necessity (CPCN) at the height of the energy crises last year. Subsequently, PG&E has unsuccessfully attempted to withdraw its application, and

has reduced its participation in the project to building the substation facilities at each end of the line. Conversely, in the Bay Area, PG&E is supporting construction of the Jefferson-Martin line to improve reliability on the Peninsula. PG&E is expected to file a CPCN in September 2002. PG&E also has been meeting with representatives of San Francisco and Palo Alto to review Bay Area transmission needs at the order of CPUC Administrative Law Judge Gottstein.

The PG&E Bankruptcy creates a cloud over PG&E's ability to finance and build needed transmission facilities. PG&E has proposed to form a separate transmission utility, E-Trans, as part of its reorganization plan. It is possible that this entity might be more motivated to develop more transmission facilities, since doing so would increase its rate base. Even if this is true, however, PG&E is likely to request accelerated depreciation treatment, a higher equity/debt ratio, and a higher rate of return than on historical transmission projects. The effects of each of these actions would be to increase the cost to consumers to fund the transmission upgrades. The CPUC has submitted a rival reorganization plan that would not spin off the transmission activities of PG&E. The net effect of these rival plans is that there likely will continue to be uncertainty regarding PG&E's ability to develop the transmission infrastructure needed to improve the reliability of electric service to the City.

### Alternatives to PG&E Transmission Service

As explained above, the fixed costs of transmission are recovered on a widespread basis – regionally in the past with more and more being spread Statewide in the future. The trend to recover the costs associated with congestion is just the opposite – i.e., the Comprehensive Market Design filing would recover those costs locally. These two factors, combined with the need to improve electric service reliability while enabling the shut down of power plants in the City, has led the City to place a high priority on having additional transmission facilities built by PG&E. PG&E, with CAISO approval, has made some additions to the transmission system serving the Greater Bay Area and San Francisco. The City has been very active in promoting those additions. Despite these successes, substantial limitations still exist. As the existing system is upgraded to better serve load reliably, it becomes less likely that additional transmission will be constructed to decrease the reliance on high-cost local generation. The result will be potential exposure to congestion charges.

The City has alternatives to PG&E transmission service, some of which could enable it to increase the capability and/or reduce the cost of the transmission system serving San Francisco and the Greater Bay Area.

### Metered Subsystem

As part of its Comprehensive Market Design, the CAISO is refining the existing concept of a Metered Subsystem (MSS), to address concerns raised regarding the integration of Governmental Entities into CAISO operations. The fundamental characteristics of an MSS are that it:

- has its Load in a geographically contiguous Service Area, subsumed within the CAISO Control Area;

- has been operating for a number of years prior to the CAISO Operations Date as a vertically integrated utility with Load serving responsibility;
- has Generation, either owned or contracted;
- may own transmission or have an Entitlement to transmission; and
- is not subject to regulation by the California Public Utilities Commission ("CPUC") or FERC.

Potential benefits of participating in the CAISO as an MSS include:

- Reduced risk of curtailments during CAISO System Emergencies resulting from identifiable resource deficiencies of other Load Serving Entities.
  - Pro-rata curtailments only during System Emergencies not due to resource insufficiency.
- Greater control over own generation to meet local needs and resource optimization objectives.
  - Resources only available for CAISO dispatch during System Emergencies not due to resource insufficiency.
- Reduced exposure to some CAISO charges (applied to net load vs. gross load).

The CAISO has not yet filed tariff language describing the requirements, rights and obligations of a Metered Subsystem, and FERC will need to act on such a filing before it would be an alternative for the City. Assuming FERC acts favorably on the MSS portion of the ISO's Comprehensive Market Design filing, the City should evaluate the benefits and risks of becoming an MSS for additional load served using the CAISO grid, and upon termination of the City's existing agreement with PG&E.

### **Participating Transmission Owner (PTO)**

The CAISO tariff provides for entities that own transmission facilities to apply to become Participating Transmission Owners (PTO). A PTO is a Transmission Owner that has turned operational control of its transmission facilities to the ISO. When the CAISO was formed, PG&E, Southern California Edison, and San Diego Gas & Electric were the original PTOs. On January 1, 2001, the City of Vernon became the first new PTO, and the City of Azusa submitted its application to the CAISO to become a PTO on June 3, 2002. One of the main advantages of becoming a PTO, especially for entities that have a large proportion of relatively new, high-cost transmission, is that each PTO's transmission revenue requirement is aggregated and included in each Transmission Access Charge Area's access charge. If an entity's average transmission access costs for its own facilities are greater than the TAC area average cost, becoming a PTO can provide economic benefits.

If the City should decide to serve electric customers directly from its transmission system within the City, and it becomes a Participating Transmission Owner (PTO), then the cost of that part of its transmission system that is at 230 kV will be recovered from all CAISO access fee customers regionally and statewide. The costs of its transmission system below 230 kV (probably 115 kV) would be recovered from its

own customers. Since the City owns substantial transmission outside of the City (that presumably has a low cost basis, given its age), that is currently designated as a generation tie, any analysis of the consequences of becoming a PTO would need to include the possibility of any impacts on that system which delivers power to Hetch Hetchy's customers in the Central Valley (MID and TID) and to Warnerville and Newark Substations as part of existing contract service PG&E provides to Municipal Load.

### Transmission Development and Funding

The City could become a project developer and/or a funding vehicle for additional transmission into the Bay Area and into San Francisco. The existing CAISO tariff envisions "market participants" funding new transmission and recovering congestion revenues associated with the new capacity. Since new transmission usually will eliminate or substantially reduce the amount of congestion charges, it is unrealistic to assume this will provide an adequate incentive for transmission investment. This is particularly true when only a subset of consumers in the constrained zone are exposed to the congestion charges, such as in the Bay Area, where most customers would pay the weighted average PGE3 price, but some municipal utilities could be exposed to potentially higher Bay Area prices. Because such "market participant" funded transmission investments are unlikely, other approaches will need to be explored, particularly ones in which the costs of transmission expansion are spread over a large number of customers.

#### Path 15 Expansion Example

The CAISO grid is composed of the transmission system of the three founding PTO's (PG&E, SCE and SDG&E) and one new PTO, the City of Vernon (on June 3, 2002, the City of Azusa submitted its application to the CAISO to become a PTO). The first stages of major new transmission projects which may provide a partial roadmap of how the City would participate as a developer and/or as a funder of transmission is contained in the proposal for an upgrade to Path 15, a major transmission link between Northern and Southern California. Since this proposal is in the early stages of development with respect to how the "Project Participants" will share the rights to the project and recover their respective investment, the example it provides is not a well defined one but it does provide some clues as to how new transmission that is owned by entities other than the existing PTO's will be added to the CAISO grid and how cost recovery may be provided.

The proposal to increase the south-to-north path rating of Path 15 from 3900 MW to 5400 MW was started by the Transmission Agency of Northern California (TANC), a group of municipal utilities in Northern California. The current proposal does not involve TANC but is funded by Trans-Elect, a new privately owned entity that has purchased other transmission systems and operated them on a cost of service basis subject to FERC jurisdiction. It is currently envisioned to be owned by the Federal Government, through the Western Area Power Administration (Western), Trans-Elect, and PG&E. PG&E would build the termination facilities for the new line. Western envisions turning over Operational Control of its capacity entitlements in the Path 15

expansion of the CAISO grid to the ISO, provided the CAISO makes the necessary changes to its tariff to allow Western to turn over control of that capacity without turning over control of all of its existing Central Valley Project (CVP) transmission system.

No new construction for the Path 15 upgrade would occur until all the issues for cost recovery were determined. It is not uncommon for a project of this magnitude to change its physical configuration and/or funding/ownership characteristics as it is developed.

### **Investment Cost Recovery Issues**

Under the CAISO tariff, costs for new high voltage transmission are recovered from all CAISO customers if the project is needed for reliability, or if it can be justified by the cumulative benefits vs. the costs of the new facilities. The FERC's assessment of these issues will be strongly influenced by the ISO. Theoretically, PG&E is required to build new transmission facilities that are needed to meet the CAISO Reliability Standards. It is possible that the CAISO could have a different interpretation on the need for a reliability project and the City could, as project developer, assist in the construction of a project justified solely on reliability criteria violations. PG&E has not proposed any transmission project in advance of the need to meet minimum reliability standards. Therefore, it is likely that a City-sponsored transmission project would need to be justified based upon net economic benefits. If some of the existing Hetch Hetchy rights-of-way were utilized for the new transmission, it would create the opportunity for City ownership without the investment of new capital because of the value that could be attributed to the critical right-of-way by a team, which would provide for project development. It is likely that the City would not have to turn over its existing transmission to the CAISO if it did not want to, either based upon its designation as a generation tie or based upon a prior exemption granted for the Path 15 project.

Silicon Valley Power (the City of Santa Clara), the City of Palo Alto, and/or the City of Alameda are potential co-sponsors of a transmission project that increases the transmission capacity to the Bay Area. Two of these entities co-funded with Hetch Hetchy, a feasibility study of such a project in the early 1990s. Hetch Hetchy also had the Electric Power Research Institute (EPRI) study the cost and feasibility of utilizing some of the existing Hetch Hetchy rights-of-way and existing towers for a new transmission line.

### **Targeted Transmission Service**

Hetch Hetchy is in the process of developing a new 115/12kv substation and 115kv underground transmission lines to connect the substation at Hunter's Point and/or Potrero switchyards. The purpose of the project is to serve Municipal Load, chiefly the new Muni Third Street project in a reliable and economic fashion. Since there are major economies of scale involved in transmission projects, it is likely the characteristics of this project would change if the goal of the City were to serve more than Municipal Load as defined in the City's contract with PG&E.

If the City chose to supply customers through Community Aggregation or from its own facilities it would experience the same TAC charges as are embedded in the PG&E retail rates. However, since PG&E currently spreads its total transmission costs across all its customers regardless of their location, the City could potentially have a cost advantage vs. PG&E. If the City delivered power to some customers through its own transmission and distribution system and it interconnected to the CAISO (PG&E) system at 230 kV, it would only experience the High Voltage Access charge (about 40% of the total). CPUC regulations regarding “exit fees” and allocation of Department of Water Resources/California Energy Resource Scheduler costs for long-term contracts will affect the viability of this opportunity. This opportunity likely will be most promising for new electric loads, since potential “exit fee” issues should be lower.

### **Separate Control Area**

The Department of Water and Power of the City of Los Angeles is an example of a large municipally owned integrated utility in California that operates a separate control area from the one controlled by the ISO. Although the integrated municipal utilities in Northern California are partially served from CAISO facilities under existing contracts, their transmission is not part of the CAISO control area. The Sacramento Municipal Utility District (SMUD) has a target date of June 18, 2002 for creating a separate control area.

Advantages of not being part of the CAISO control area include the potential to escape some of the substantial CAISO charges and increased control over generation and transmission resources to meet local reliability and pricing objectives. A disadvantage of an entity being its own control area is that the transmission costs cannot be spread to all TAC area customers.

## **Key Considerations of Alternatives to PG&E Transmission Service**

### **Rates and Pricing**

Transmission service rates and pricing will be driven by the tariffs and market designs approved by FERC. Within a given market construct, however, the ownership of the transmission facilities can affect the transmission pricing for consumers. Transmission service pricing and how it would relate to each ownership condition is discussed below.

### **PG&E Transmission Service**

#### **Pros**

- Initially, under the Comprehensive Market Design proposal, City retail customers would be protected from increased energy prices due to transmission congestion.

**Cons**

- Transmission rates would be regulated by FERC and allocated to retail customers by the CPUC. The City's control over transmission service issues (costs and rates, maintenance, etc.) would be limited to interventions in PG&E and CAISO proceedings at FERC and the CPUC, and bi-lateral discussions with PG&E.
- CPUC procurement proceeding decisions could impact delivered energy cost, locational capacity obligation costs, and long-term resource costs
- Potential transition to separate, higher Bay Area or San Francisco nodal pricing depending on CAISO and PG&E decisions.
- PG&E's bankruptcy proceeding could significantly impact final retail rates.
- Financing costs associated with new transmission facilities developed by private companies would be higher than for those developed by a municipal entity.

**SFPUC or New Municipal Agency Transmission Service****Pros**

- The SFPUC or new municipal entity could construct new transmission into the Bay Area and potentially join a municipal control area; this would enable it to avoid potential transmission congestion charges and CAISO grid management charges.
- Transmission rates, though regulated by FERC, would be allocated to retail customers by the SFPUC or new municipal entity, giving the City greater control over transmission service issues (costs and rates, maintenance, etc.).
- Financing costs associated with new transmission facilities developed by the SFPUC or a new municipal entity would be lower than for those developed by a private entity.
- Targeted transmission projects could result in an attractive revenue stream, providing benefits to all City consumers, as well as to the specific customers connected to the SFPUC and/or new municipal entity's transmission facilities.

**Cons**

- Costs to serve current PG&E retail customers under Community Aggregation potentially could be higher than existing PG&E retail service if those customers would no longer be included in the PGE3 Load Aggregation for settlements purposes.
- Similarly, if the City municipalizes, its customers might no longer be considered to be part of the PGE3 Load Aggregation and could be exposed to higher locational capacity obligation costs
- FERC is considering alternative transmission access charge cost allocation methodologies as part of its Standard Market Design proceedings that could result in the costs for new facilities being allocated to the beneficiaries, rather than on a broader scale.

### Reliability

The reliability of the transmission system is largely driven by the actions of the ISO, but the City's ability to influence transmission facility decisions could increase if it expands its involvement in electricity services.

#### PG&E Transmission Service

##### Pros

- PG&E recently has taken steps to improve reliability to the City by making additions to the transmission system serving the City, and has proposed others for the near future, including the Jefferson-Martin 230 kV line.
- PG&E may get more aggressive in constructing new transmission facilities if they are allowed to "spin off" the transmission assets into a separately regulated company.

##### Cons

- PG&E has not shown a willingness to aggressively pursue all economically justified transmission.

#### SFPUC or New Municipal Agency Transmission Service

##### Pros

- If the SFPUC or new municipal entity were to become a metered subsystem or join a municipal control area, its exposure to curtailments due to potential resource insufficiency of PG&E would be lower.
- The SFPUC or new municipal entity could take a more active role in developing and/or funding new transmission and generation facilities on the Peninsula and into the Bay Area to improve reliability.

##### Cons

- The SFPUC or new municipal entity would be exposed to shortages caused by the lack of availability of its own resources.

### Local Control

Local control refers to the perceived and actual ability of the customer to influence the policies and activities of the public agency and the ability of the governing body to more readily respond to local environmental and social needs. Local control allows self-regulation and the freedom to consider only constituent needs and sound business practices, not shareholders. The following are some considerations with respect to transmission in regard to local control.

### **PG&E Transmission Service**

#### **Pros**

- None identified.

#### **Cons**

- The City's ability to influence Bay Area transmission planning and pricing is limited to participating in ISO, FERC and CPUC proceedings, and to bi-lateral discussions with PG&E.

### **SFPUC or New Municipal Agency Transmission Service**

#### **Pros**

- City residential and business consumers would have a stronger voice in setting policies for electric transmission service, including the ability to set higher reliability standards, to build economically justified additions, and to allocate costs.

#### **Cons**

- The SFPUC or new municipal entity would need to coordinate its transmission planning, development and operations activities with the ISO, PG&E and other Northern California municipal utilities.
- If the SFPUC or new municipal entity pursues targeted transmission opportunities, it would need to address potential equity concerns from consumers in areas not served by those facilities.

## **Transmission Governance Issues**

**Appendix C** on Governance Issues describes the existing authority of the SFPUC and the City to provide energy services, as well as the authority that could be obtained via formation of a municipal utility or municipal utility district. Given the authorities described in that section, the City likely could pursue the alternatives to PG&E transmission service described above either with the SFPUC as the vehicle or through formation of a municipal utility entity (municipal utility or municipal utility district). In either case, the most important characteristic for success would be the City's willingness to adopt a policy to pursue the alternatives and to allocate sufficient staff and budget resources.

The City's ability to quickly and easily raise funds for energy infrastructure projects will be important. Given that the SFPUC currently has some restrictions on its ability to use revenue bonds to raise funds, changes to the City's charter may be needed to increase the number of funding options. Although some of these opportunities could be developed without revenue bond financing, the existence of that option could increase the chance of success.

Some of the alternatives could benefit through prudent exercise of the power of condemnation, such as development of new transmission facilities and/or participation in a municipal control area. Conversely, targeted transmission service to new large retail customers by expanding the current transmission system probably would occur through minor extensions of that transmission system in the public streets and not require condemnation rights. California Code of Civil Procedure section 1240.125 authorizes a "local public entity" to acquire extraterritorial property by eminent domain for "electric supply purposes" if the public entity is otherwise authorized to acquire property by eminent domain for such purposes. Section 1240.125 states:

"Except as otherwise expressly provided by statute and subject to any limitations imposed by statute, a local public entity may acquire property by eminent domain outside its territorial limits for water, gas, or electric supply purposes or for airports, drainage or sewer purposes if it is authorized to acquire property by eminent domain for the purposes for which the property is to be acquired."

The term "local public entity" is defined to include "any public entity other than the state." (Code of Civil Procedure section 1235.150)

Cities are authorized to "acquire by eminent domain any property necessary to carry out any of its powers or functions." (Government Code section 37350.5) Similarly, a municipal utility district formed under the Municipal Utility District Act, "may exercise the right of eminent domain to take any property necessary or convenient to the exercise of the powers granted" in the Act. (Public Utilities Code Section 12703). A municipal utility district may condemn property "within or without the district necessary to the full or convenient exercise of its powers." (Public Utilities Code Section 12771)

Given the broad condemnation powers noted above, the City appears to have adequate ability to pursue the alternatives to PG&E transmission service that might require condemnation using either the SFPUC or a new municipal entity as the vehicle. However, to avoid some of the issues associated with condemnation, the City could concentrate first on those opportunities that do not require condemnation.

## Transmission Service Conclusions

- Even though the transmission system to the City is planned according to standards equal to or higher than those used elsewhere in California, electric consumers in the City continue to obtain less reliable transmission service than other parts of the State due to a dependence on old, unreliable, and emissions-limited generation at Hunter's Point and Potrero Power Plants.
- New transmission built by PG&E into the Bay Area and within the Bay Area will tend to increase reliability and reduce costs to electric consumers in San Francisco.
  - Under current regulations the fixed costs of such facilities are spread widely, but transmission congestion charges are proposed to be recovered locally

- Although PG&E recently has completed, and has planned additional transmission to the Bay Area and within the Bay Area to San Francisco, it is unlikely that PG&E will build enough transmission to completely mitigate exposure to higher prices due to transmission congestion.
- Developing local, City-controlled generation can provide similar benefits to new transmission by increasing reliability and decreasing exposure to congestion charges.
  - Projects similar to those identified in the City's Energy Plan should be further explored.
- There are opportunities to provide greater influence on the addition of new transmission and generation resources that should be investigated further:
  - Developing new transmission and turning its control over to the CAISO may be the least-cost method for the City to more actively promote new transmission.
  - Developing a separate control area would provide the greatest level of local control, but its cost impacts need to be weighed against the benefits.
- Both the SFPUC and/or a new municipal entity (municipal utility or municipal utility district) could provide an appropriate vehicle to pursue needed transmission projects.
- The SFPUC or new municipal entity should explore targeted transmission projects that could result in an attractive revenue stream, providing benefits to all City consumers, as well as to specific customers connected to the SFPUC or new municipal entity's transmission facilities.



## Section 4

# ELECTRIC ENERGY AND DISTRIBUTION SERVICE ISSUES AND OPTIONS

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## Introduction

This section discusses the opportunities available to the City for municipalizing either energy service or electric distribution service.

Energy service involves generating or purchasing electrical energy, scheduling that energy for delivery, and selling the energy to ultimate retail customers. ESPs who are selling the energy commodity may look at the diversified load characteristics of a pool of retail customers or they may structure terms that price power based on the load characteristics of a single retail customer. Under Direct Access, customers would have the option of contracting for energy service through bilateral contracts or aggregation service from either the City or another ESP. Bilateral contracts allow the customer to have terms of energy service tailored to their own unique needs and load characteristics, while aggregation service attempts to lower the cost of providing energy by aggregating customer loads into more sizable and less costly load shapes. The concept of energy service is that the wires are owned and maintained by a distribution company, which are used by an ESP to deliver energy. Energy service is not a monopoly service and would need to compete with PG&E, other aggregators and ESPs.

Distribution service would allow the City to provide delivery of energy to voltages less than 69 kV, whether or not the City combines distribution service with energy service. Distribution service would most likely be unbundled for billing purposes. Distribution service would require maintenance, operation, and development or purchase of a distribution system that could either compete with PG&E or replace PG&E as the monopoly distribution service provider for San Francisco.

There are a number of ways the City could provide either municipalized energy or distribution services which are described in more detail below.

## Energy Service Comparison

### Introduction and History

AB 1890 envisioned development of an active retail market for energy in which a customer, or groups of customers, would have control over the terms of their energy service from new Energy Service Providers. This market for retail energy service came to be known as Direct Access. However, at the outset of deregulation, few residential or small commercial customers made use of the new Direct Access market,

since transition charges prevented them from achieving any real savings on their bills. Consequently, many new ESPs initially entered and eventually exited the market. This included even well-financed providers with substantial experience in energy markets. However, a number of industrial customers were able to use their buying power to reduce their energy bills through contracting with an ESP. With the onset of the energy crisis and the signing of long term contracts by the CDWR, the CPUC suspended Direct Access service retroactive to September 20, 2001. Those industrial customers who had contracts in place with an ESP as of that date are still being served by those ESPs today, while any new contracts are prohibited.

Although Direct Access has been suspended by the CPUC, a new California bill, AB 117, authored by Assembly Member Migden, would re-instate Direct Access service on a limited basis. AB 117 would allow cities or counties to aggregate electric loads within their boundaries, but require any resident participating in aggregation service to compensate the CDWR for both current costs of energy service and any unavoidable future CDWR energy costs incurred to serve the customer's future load. It would also allow the CPUC to set exit fees or levy other charges as appropriate, for unavoidable costs that are born by other "electrical corporations" (in this case, PG&E) due to a customer choosing to receive energy from an aggregator. Direct Access service, as envisioned by this bill or in some other capacity, would need to be reinstated either through legislative action or through the CPUC before the City could offer energy service. The Migden bill will need to be closely followed if the City plans to offer energy service through community aggregation.

There is still significant uncertainty in wholesale markets, as disclosed in Section 2. Many of the same factors that led to very high wholesale energy prices last year still exist today. A number of reliable agencies continue to forecast power shortages in California, suggesting prices for wholesale power would increase in absence of FERC price mitigation. Unsettled wholesale energy market conditions, along with reasonable volatility in energy prices, are likely going to continue.

## San Francisco's Current Energy Service

Existing energy service in San Francisco is primarily provided by PG&E through its franchise granted by the CPUC. PG&E owns both hydroelectric and nuclear facilities to generate power for delivery to their retail customers and has long-term contracts to purchase electricity from other generators. Any electric demand that is greater than PG&E's generation resources is provided by the CDWR. The CPUC is currently investigating how and when PG&E will take back the purchasing obligation from the CDWR. Any transition will depend on restoration of PG&E's creditworthiness, which is being litigated and resolved in PG&E's bankruptcy case. These issues will need to be tracked and evaluated to determine what role PG&E will play in the energy future of San Francisco.

In addition to PG&E, the City, through the SFPUC, currently serves some wholesale electric loads from power produced by Hetch Hetchy reservoir. Hetch Hetchy produces on average about 1.7 billionkWh per year and delivers this power to Turlock, Modesto, and certain retail loads within San Francisco. A new analysis

would have to be conducted to determine if any power could be made available from Hetch Hetchy to other retail loads in the City. The SFPUC delivers some of this energy on transmission and distribution lines owned by the City. The SFPUC regulates the terms of power sales to its retail customers, including price, term, quantity, and delivery points.

### Alternatives to PG&E Energy Service

Assuming Direct Access is reinstated, the City as well as other ESPs could offer energy services to retail City loads, competing directly with PG&E's current energy service. There are four ways the City could offer energy service to retail customers:

- **Facilitate Aggregation Through an Existing ESP.** The City would solicit proposals from ESPs, select one and negotiate general terms of service arrangements. The ESP would contract and settle transactions directly with customers, thus the City would have no financial risk. The ESP, in conjunction with the City, would market its service to customers and aggregate targeted loads to minimize procurement costs. Currently there are few ESP available to contract with.
- **Become a Standard Aggregator.** The City would commit to one or more supply contracts to provide retail electric service. The City could market its energy service to all loads in the City, just loads near its primary service area or transmission and distribution facilities, or to loads outside of the City. The City would determine which loads to aggregate in order to create a consistent and manageable load profile. The City could determine whether or not to pass market price risk on to customers and in what fashion. Depending on how market risks were passed on, the City may be exposed to substantial price risk. Retail energy prices could be fixed long-term, indexed, or guaranteed to be a percentage below PG&E energy rates. The City would need to market to retail customers in order to provide them incentive to switch from default PG&E service.
- **Become an Aggregator Through Community Aggregation (Migden Bill).** This option would be the same as the option of becoming a standard aggregator except that the City would not need to initially compete with other ESPs to capture the City's entire retail load. The Migden bill currently provides that all of the City's retail load would automatically be transferred to the City aggregation service unless a customer directly expressed the desire to opt out. Requiring retail load to opt out of the City's aggregation service should provide the City with a competitive advantage over other forms of aggregation service. Community aggregation service could only be provided within the boundaries of the community and not to customers outside those boundaries. Risks in providing this service are similar to standard aggregation risks, except the City would not have to compete for initial customers.
- **Bilateral Contracting.** The City could sign bilateral energy contracts with strategically located large customers. The contracts could tailor price, length of service, delivery points, quantity, voltage level, and energy scheduling or service

options directly to the customer's unique needs. Depending on how the City supplied and priced the power, the City may be exposed to significant risks.

# Key Considerations of Alternatives to PG&E Energy Service

## Rates and Pricing

### PG&E Provides Energy Service

- PG&E has no financial incentive to continue buying and selling the energy commodity. Therefore, PG&E has no incentive to bear any risk associated with market energy price volatility. PG&E would like to pass all risk to customers as PG&E currently does with retail natural gas prices.
- PG&E does not have sufficient financial incentive to manage the risks associated with energy purchasing and volatile customer loads through the use of long term contracts or appropriate financial instruments that help limit price exposure.
- PG&E's proposal in its bankruptcy proceeding would transfer ownership of strategic generation resources to its less regulated affiliate (regulated only by FERC). If approved and upheld in court, these generation resources would transition to market prices. PG&E's plan would also provide an immediate increase in the retail price of retained generation.

### SFPUC or San Francisco Municipal Utility Provides Energy Service

Under this scenario, the costs and retail prices for energy would be managed and controlled by the governing body of the City's electric service provider, either the current SFPUC or a different form of San Francisco municipal utility.

#### Pros

- The governing board could enhance retail price stability by creating financial reserves that help the utility manage both volatility in energy market prices and retail customer's loads.
- The governing board could determine what approaches to use to manage volatile energy prices and risks, whether through financial instruments, long term contracts, or new generation.
- Energy-only service would avoid the expenses and risks associated with acquiring, owning and operating delivery facilities.
- The City could price energy to customers based on their unique load patterns. Customers would not need to be aggregated for pricing purposes and the City would have the flexibility to tailor energy pricing to local customer needs. As long as CPUC regulation of retail energy rates continues, PG&E will have no financial incentive to tailor retail energy rates to local needs.

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## ELECTRIC ENERGY AND DISTRIBUTION SERVICE ISSUES AND OPTIONS

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### Cons

- Direct access service would require new purchase agreements or generation sources to meet retail loads in the SF Muni.
- Energy service would require managing volatile energy prices and customer loads as well as coordination with historically congested CAISO transmission markets. Poor management of these risks could result in higher retail prices.
- Numerous electric support services would be required, such as: customer care systems, pricing programs and cost recovery, billing, accounting, advertising, government affairs, human resources, safety, management, and regulatory support. Some of the initial expense of these services could be offset if the SFPUC offers aggregation service, as these services are already provided to water and wastewater customers, as well as municipal electric customers receiving Hetch Hetchy power.

### Reliability

#### PG&E Provides Energy Service

- Based on financial conditions, PG&E may decide it can not fulfill its retail load obligations, potentially causing blackouts.
- Until 2000–2001, PG&E had always fulfilled its obligation to serve. PG&E has the energy traders, schedulers, dispatchers, and managers in place to reliably offer energy service.

#### SFPUC or San Francisco Municipal Utility Provides Energy Service

##### Pros

- Serving retail energy loads within the SF Muni would allow the SF Muni to ensure that all retail load is fully contracted for at prices negotiated by the SF Muni. Having enough resources under contract to meet the retail loads of the SF Muni would help the SF Muni avoid blackouts caused by lack of payment.

##### Cons

- Even if the SF Muni's retail load was fully contracted for, the SF Muni could still be exposed to rolling blackouts through its interconnection agreements with PG&E or the CAISO. For example SMUD endured rolling blackouts during 2001 mainly because of its interconnection agreement with PG&E and not because it lacked generation or energy under contract to meet its own load.

### Local Control

#### PG&E Provides Energy Service

- The local agency would continue to have no control over issues such as market vs. fixed energy pricing, financial reserves allocated to provide stability in energy

prices, or the type and cost of new generation facilities or contracts. Energy services are about 70% of PG&E's bundled system average rates. Influence over energy service issues would be limited to CPUC, CEC, and FERC regulatory forums.

- Energy production costs, rate designs, and special pricing packages or contracts would not necessarily meet the needs of local customers.

### **SFPUC or San Francisco Municipal Utility Provides Energy Service**

#### **Pros**

- There are no service area restrictions for an ESP in California thus the City could offer energy service (but not community aggregation service) to compatible loads anywhere in the state.
- Constituents could influence decisions on capital expenditures, including types of generation and the resource portfolio mix (e.g., percent renewable), as well as policies on distributed generation and net metering.
- Public policy issues like low-income programs and services, environmental impacts, and energy efficiency could be managed through energy-only service although historically, the responsibility for public benefit programs has been assigned to and paid for by the distribution service company.
- Energy contracting, pricing, and portfolio characteristics could be available for public comment and debate and would be controlled by the governing board of the SF Muni.

#### **Cons**

- Political factions may prevent swift decisions from being made in volatile, rapidly-changing energy markets.

The following table summarizes the options for providing aggregation service and how they relate to key components of energy service.

**Table 4-1**  
**Comparison of Governance Options for Energy Service**

| Characteristic of Service | PG&E Provides Energy Service                                                                                                                                                                      | SFPUC or San Francisco Municipal Utility Provides Energy Service                                                                                                                 |
|---------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Pricing/Rates             | ■ PG&E has a financial incentive to transfer market price risk to customers. As long as bundled service is CPUC-regulated, PG&E is unable to effectively link wholesale costs and retail tariffs. | ■ SF Muni Board would regulate the price and cost of energy as well as the retail pricing options available to customers.                                                        |
| Reliability               | ■ Financial emergency may affect reliability.                                                                                                                                                     | ■ SF Muni could ensure all retail loads are met with contracted or generated energy.                                                                                             |
| Local Control             | ■ PG&E energy service continues to be regulated by FERC, CEC, or CPUC. Limited incentive to offer energy services that meet local needs.                                                          | ■ Public would have opportunity to influence financial reserves, pricing options, and energy sources. Local residents could define how the SF Muni deals with market price risk. |

## Distribution Service Comparison

### Introduction and History

Electric distribution service in California is provided by one of two types of entities: municipal (public) providers or investor-owned (private) utilities (IOUs). The following table details the major differences and similarities between the two options for electric distribution service.

**Table 4-2**  
**Comparison of Distribution Services Between Public Utilities and IOUs**

| Service                 | Public/Muni Service                                                                                                                            | PG&E Distribution Service                                                                                                                                                                                                                                                         |
|-------------------------|------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Electric Design, O&M    | ■ Similar design standards and construction practices. O&M can depend on budget allocations and be affected by distribution system conditions. |                                                                                                                                                                                                                                                                                   |
| Reliability             | ■ Similar standards, both measure SAIFI & SAIDI indexes and attempt to minimize outages.                                                       |                                                                                                                                                                                                                                                                                   |
| Safety                  | ■ Both adhere to General Order 95 and 128 standards.                                                                                           |                                                                                                                                                                                                                                                                                   |
| Financing               | ■ Financing comes mainly from tax-exempt bonds.                                                                                                | <ul style="list-style-type: none"> <li>■ Typically a higher cost of capital that is composed of bonds as well as common and preferred stock.</li> <li>■ Has limited access to tax-exempt debt.</li> <li>■ Financing cost and access can be volatile and unpredictable.</li> </ul> |
| Rates/Pricing           | ■ Historical prices have averaged 20% below IOUs for similar customer segments.                                                                | ■ Already have unbundled prices for all customer segments. Usually more pricing options than Muni.                                                                                                                                                                                |
| Taxes                   | ■ Publics are exempt from income taxes, some property taxes, and most franchise fees.                                                          | ■ IOU's pay income taxes, property taxes, and franchise fees.                                                                                                                                                                                                                     |
| Regulation              | ■ Self-regulated by an elected governing body.                                                                                                 | ■ Regulated by at least the CPUC and FERC                                                                                                                                                                                                                                         |
| Public Purpose Programs | ■ Usually more emphasis on low-income programs, (with community involvement) in mix of public purpose programs.                                | ■ Provides public purpose programs with CPUC oversight                                                                                                                                                                                                                            |
| Resource Mix            | ■ Usually have more federal hydro power than IOUs.                                                                                             | ■ IOU's have limited and declining access to federal hydro power.                                                                                                                                                                                                                 |

The debate over whether public or private ownership of electric utilities is superior is decades old. Supporters of private industry argue that public ownership is less efficient, depends on tax subsidies, is too risk averse, is dependent on inexpensive federal power, and is too slow to react and market into changing technology and market price conditions. Public power advocates dispute the efficiency claim, point to average costs that are historically 20% lower, tout local control and lack of profit distributions, and note that the privately-owned utilities have more outstanding tax-exempt debt than do publicly-owned utilities. There are few significant differences between public and private when it comes to distribution design, reliability or safety.

## San Francisco's Current Distribution Service

Existing electric distribution service in San Francisco is provided to non-municipal loads by PG&E through their franchise granted by the CPUC. PG&E provides bundled electric service to the majority of the electric load in the City. In other words, PG&E provides customers both energy and delivery (transmission and distribution) services as well as billing, metering, customer service, maintenance, upgrades, and new construction. There are very few viable and economic options for customers

hoping to avoid PG&E's distribution service. The most obvious is acquisition of the distribution system by a public entity.

In exchange for an exclusive distribution franchise, PG&E is regulated by the CPUC and other local agencies and commissions for environmental and construction permitting. PG&E's distribution pricing, terms of service, connection fees, billing, maintenance, design standards, construction, environmental compliance, and project planning are all regulated. Customers or their representatives may intervene in PG&E rates cases before the CPUC to attempt to influence the characteristics of their distribution service. PG&E has little flexibility in tailoring distribution service to fit local needs and will only continue to have an incentive to develop and offer distribution service as long as the CPUC allows them a reasonable return on distribution infrastructure. Shareholder concerns and profit motives will continue to define the ultimate terms and conditions of PG&E distribution service in San Francisco.

### **Alternatives to PG&E Distribution Services**

There are two primary ways the City could municipalize it's distribution service, either serve 100% of the City's residents and businesses or serve only small subsets of those customers (spot municipalization). In addition, there are two ways in which these services could be governed, either by a new municipal board or by the SFPUC. Issues of governance are dealt with in a later section and do not have a material impact on the characteristics of the distribution service options. Therefore, just the options for municipal distribution service are dealt with in this section.

#### **Serve 100% of City Residents and Businesses**

The first option for municipal distribution service is for a SF Muni to purchase PG&E's distribution lines and provide SF Muni-owned distribution service to all customers within San Francisco. The SF Muni could also construct its own parallel distribution system to compete directly with PG&E's system. It is not likely that the construction of a parallel system to serve all of the City residents and businesses would be acceptable or practical for San Francisco and this option will not be discussed further here. The new utility would therefore need to purchase and acquire the current PG&E distribution system. A careful analysis of severing the acquired distribution system from the rest of PG&E's system would need to be performed as part of any feasibility study. The utility could be governed by a new utility board or by expanding the role of the SFPUC. The final retail distribution price paid by end-users would be regulated by the SF Muni and may include other non-bypassable fees collected on behalf of the CDWR or PG&E. The following are some key issues involved with offering this service.

##### **Pros**

- A SF Muni would have a lower cost of capital than PG&E and would avoid many of the taxes paid by PG&E. The Impact of lost taxes would need to be dealt with.

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- A SF Muni would control the terms of service and prices for distribution service. Distribution service currently contributes about 15-20% of ultimate retail charges.
- Public policy issues with low-income programs and services, environmental issues, energy efficiency, and distributed generation could be managed effectively by offering distribution service, as Public Benefit Programs are funded through distribution charges. Local money contributed to these causes would be spent locally.

### Cons

- Purchasing PG&E's existing distribution system would likely require substantial financing (especially given PG&E's downtown network) and can be expected to face vehement political and legal opposition by PG&E.
- Distribution service would require engineering, maintenance, planning, construction, operation, safety, and dispatch personnel and equipment. Many of the required staff may come from PG&E. The transition would require new Union negotiations and contracts.
- Numerous electric support services would be required, such as: customer care systems, pricing programs and cost recovery, billing, accounting, advertising, government affairs, human resources, safety, management, regulatory support, an outage notification and management system, and emergency repair crews and equipment. The SFPUC currently provides these services for water and wastewater customers and for transmission and distribution lines owned by the City.
- The City would lose the revenues paid by PG&E. The revenue loss could be made up in distribution rates. A cost/benefit analysis of this option would quantify this impact.

## Spot Municipalization

The second option for municipalizing San Francisco's distribution services is for a SF Muni to provide distribution services in re-development zones or new service areas in the City. The SF Muni could begin this service by having developers transfer distribution assets from new development or re-development to the SF Muni rather than to PG&E. Developers and the SF Muni would avoid paying the up-front 34% gift tax to PG&E. The final retail distribution price of electricity would be regulated by the SF Muni and may include non-bypassable charges required by state law. Studies would need to be conducted to determine which areas would be best served by the SF Muni-owned distribution system and which should remain on the PG&E owned system. The following are some key issues involved with offering this type of distribution service.

### Pros

- A SF Muni would have a lower cost of capital than PG&E and would avoid many of the taxes paid by PG&E. The Impact of lost taxes would need to be dealt with.

## **ELECTRIC ENERGY AND DISTRIBUTION SERVICE ISSUES AND OPTIONS**

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- A SF Muni would control the terms of service and prices for distribution service. Distribution service currently contributes about 15-20% of ultimate retail charges.
- Delivery service to only new customers through redevelopment work would have the lowest acquisition cost of either distribution service option, but would still require substantial investments in the support services listed above.

### **Cons**

- For most customers, distribution prices, terms of service, construction practices, maintenance expenses, and outages would be managed by PG&E and regulated by the CPUC. The SF Muni would manage and regulate these aspects of distribution service for only those customers who were connected to the portion of the distribution system owned by the SF Muni.
- Spot municipalization could force the SF Muni to wheel over and through PG&E's distribution or primary electric system.
- The SF Muni's public purpose programs could not be standardized throughout San Francisco, as most City residents and businesses would remain on PG&E service.
- There would need to be active coordination between the SF Muni and PG&E for distribution service maintenance, operation, restoration of power, and repair as the City's distribution system would be imbedded within and surrounded by PG&E's distribution system.
- Maintaining, improving, and developing a fragmented distribution system would be more costly and difficult than if the system were an integrated whole. Also, because costs would be spread over a relatively small number of customers and usage, average costs may be somewhat higher than for other approaches.
- Issues of fairness may arise as some customers would receive electric distribution service controlled by the SF Muni, while others would continue receiving distribution service owned by PG&E and regulated by the CPUC.

## **Key Considerations of Alternatives to PG&E Distribution Services**

### **Rates and Pricing**

Distribution service rates and pricing ultimately depends on who owns, manages, controls, and regulates the distribution system. Distribution system pricing and how it would relate to each ownership condition is discussed below.

#### **PG&E Owns Distribution**

- Distribution retail rates would be regulated by the CPUC. The City's control over distribution service issues (costs and rates, maintenance, hook-up fees,

construction practices, etc.) would be limited to interventions in PG&E rate cases before the CPUC.

- The result of PG&E's bankruptcy proceeding could significantly impact final retail rates. Alternative plans by the CPUC and PG&E have been filed with the bankruptcy court for consideration by creditors. After a vote by creditors, the bankruptcy judge will hold confirmation hearings on the plans. If PG&E's plan is adopted and withstands legal challenges, PG&E's distribution service would continue to be regulated by the CPUC, while transmission and energy commodity prices would be regulated by FERC or set by market forces.
- Conservation, energy efficiency, and other public purpose programs would be regulated by the CPUC and not tailored to local needs. Local contributions to these causes through PG&E rates would not necessarily be spent locally.
- San Francisco residents would pay higher costs for financing and taxes than they would pay with a municipal provider.
- Rate options, customer segments, and special rate contracts would be managed by PG&E and regulated by the CPUC and would not necessarily meet local needs.
- Rate design priorities (cost equity, rate stability, and competitiveness) would be managed by PG&E and regulated by the CPUC.
- PG&E would determine, in conjunction with the CPUC and other parties, when and by how much to raise distribution rates.

### **SFPUC or New Municipal Agency Offers 100% of Distribution Service**

#### **Pros**

- The SFPUC or new municipal agency would determine ultimate distribution rates, customer segments, and distribution service options. The City would be free to design rates, set rate recovery priorities, offer rate stability mechanisms, and set competitive rates without oversight or management by PG&E or the CPUC.
- The City could control costs and rates, hook-up fees, and distribution construction practices and tailor these services to local needs.
- Public purpose program dollars would be collected and spent locally. Program priorities, funding levels, and options would be determined by the City.
- The City may be able to offer lower priced long run distribution service because of lower tax requirements and no profit motive. Profits and taxes have historically average about 30% of operating revenue for PG&E. The 30% is calculated from PG&E's 1995 – 1999 FERC Form 1s. During that five-year period, PG&E's average tax load (local, state, and federal) was 15.0% of operating revenues. During the same period, their average net income was 15.2% of operating revenue, resulting in a combined tax/profit load of 30%. These lower costs may be offset by the initial purchase price and whether or not it exceeds book value.

## ELECTRIC ENERGY AND DISTRIBUTION SERVICE ISSUES AND OPTIONS

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- Distribution rates for some customers might be able to be reduced. Any reduction would depend on the purchase price of the distribution system, how network costs are allocated, and average energy use per customer. The fact that the distribution service area in the city is highly concentrated would also support lower distribution system pricing.

### Cons

- The new utility would have to determine how to sever their distribution system from that of PG&E. Studies would need to be completed to determine where the severance should take place, what customers would be affected, what new distribution facilities may need to be constructed in order for the severance to take place, and how the severance would affect reliability, revenues, transmission service, and local customer concerns. These studies and the actual costs of severing the system would likely affect distribution pricing over the long run. Because San Francisco is on a peninsula and because of the types of land uses along the boundary where severance would occur, it is likely that severance costs would be relatively low.
- PG&E would not likely be willing to sell the San Francisco distribution system. PG&E's resolve in maintaining ownership of the city's distribution system was recently tested when they were faced with City and County of San Francisco ballot measures both of which were defeated after a large media campaign by PG&E. PG&E has many legitimate business reasons for owning and operating electric distribution facilities.
- PG&E has a downtown San Francisco network system that is more expensive to own, operate and maintain than other portions of PG&E's system. PG&E's current distribution rates average the cost of this network to all of PG&E's customers. In absence of averaging the cost of this network to all of PG&E customers, distribution rates for just those customers using the downtown network or for all San Francisco ratepayers could rise if not offset by other savings.
- In owning the distribution system, the new utility would also take responsibility for distribution outage notification, emergency response, and emergency system dispatch and control. The expense of these reliability systems, as well as any new infrastructure costs, including needed system upgrades, and new distribution infrastructure could be financed and collected through rates. Although these services are currently provided by PG&E in their rates, PG&E is able to spread the cost of these systems over a large customer base. The new utility would have to develop new systems or improve systems already in place for other utility services, to serve only the San Francisco market, potentially increasing the average cost of this service element.
- Exit fees or non-bypassable charges may apply.
- Costs for customer care, settlement systems, and metering would have to be incurred and collected through rates.
- Tax implications for local government would also need to be considered.

### SFPUC or New Municipal Agency Offer Spot Municipalization

#### Pros

- The SF Muni would have the distribution facilities transferred to their ownership instead of to PG&E on new construction and re-development projects. Customers would save 34% on up front capital costs, due to avoiding the gift tax that PG&E must pay on non-revenue justified plant investment.
- Distribution system costs and rates would be regulated by the SF Muni for the portion of the distribution system that it controlled. This regulation would allow the SF Muni to control distribution cost equity between customer classes, segmentation of customers, and distribution pricing tailored to customer segments.
- Spot municipalization can be done with tax-free financing on new distribution service. However, purchasing PG&E's existing system can not be done with tax exempt debt. See United States Tax Code Section 141.

#### Cons

- Distribution rates would continue to be controlled by PG&E and regulated by the CPUC for some customers, while others would receive distribution service from the SF Muni. Issues of fairness and equity may arise if PG&E's distribution pricing is significantly different from the new utilities' distribution pricing.
- Ongoing distribution O&M costs would likely be higher than PG&E, because administration, maintenance, meter reading, construction, and overhead costs would increase due the difficulty of performing these services on a fragmented utility distribution system embedded within and surrounded by PG&E owned lines. These costs would have to be born by a limited amount of customers, increasing the average cost of O&M.
- Costs for customer care, billing, credit, and payment settlements would have to be incurred and collected through rates. The average cost of these services would be high relative to offering 100% distribution service due to the limited number of customers with spot municipalization.
- Exit fees or non-bypassable charges may apply.
- Tax implications for local government would need to be considered.
- PG&E would not likely be willing to give up any of the San Francisco distribution system.
- This structure would likely discourage PG&E from assisting the new utility with project interconnection, project design and planning, and reliability issues which could increase the cost of these services for all customers.
- In owning a fragmented distribution system, the new utility would take responsibility for distribution outage notification, emergency response, and emergency system dispatch and control for at least the distribution system owned and controlled by the SF Muni. The expense of these reliability systems could be

financed and collected through rates. Although the costs of these systems and services would be similar to the costs PG&E incurs to provide these services, spot municipalization would have less customers and usage to spread these costs to, leading to higher average costs of service.

### Reliability

Regardless of who owns the distribution system, transmission service will be provided by the CAISO. As long as transmission service is provided by the CAISO, any shortages of energy experienced by CAISO would have to be partially born by the City. The reliability of electric distribution systems may vary more based on system design than ownership, as both municipally owned and IOU owned distribution systems are held to similar reliability standards in GO 95 and 128. Although distribution system reliability in the long run would likely be similar between an IOU and a municipality, the entity owning the distribution system could have some influence on reliability as noted below.

### PG&E Owns Distribution

PG&E currently provides distribution reliability services to San Francisco through rates regulated by the CPUC. If PG&E continues to own and operate distribution facilities, the incentive to continue performing reliability services would not change and the status quo would likely prevail.

### SFPUC or New Municipal Agency Offer 100% of Distribution Service

#### Pros

- The new utility would have the flexibility to tailor distribution system reliability to local needs, respond to local distribution concerns, and provide distribution services local businesses or residents may value (power quality monitoring, back-up transformers, UPS systems, distributed generation, renewable power systems, etc.). These services enhance distribution reliability by providing redundancy, back-up generation, and power quality analysis to ensure proper power flow and voltages. PG&E offers these services, but does not necessarily have the incentive to tailor these services to local needs.
- The City may have more incentive to encourage distributed generation. This can have both a negative and positive effect on reliability, but in most instances reliability would be enhanced.

#### Cons

- If a new utility were to provide distribution services it would need to hire and develop the internal staff to support the critical distribution system reliability functions.
- The utility would also need to accept the liability for environmental issues, public and employee safety, and would have to invest in a system outage notification system and a system dispatch center.

### SFPUC or New Municipal Agency Offers Spot Municipalization

#### Pros

- Spot municipalization fragments the utility system into small islands or pockets of distribution facilities. Ordinarily, such a distribution structure could cause significant interconnection issues with the IOU, since that entity would have reduced incentive to support proper interconnection of the new utility's distribution service pockets and would not be responsible for service disruptions within the pockets. The City, however, has a long history of providing reliable service to pockets of municipal electric loads under its existing agreement with PG&E.
- If spot municipalization were to encourage cogeneration and distributed generation, planning would require that reliability be a key consideration. If properly balanced, reliability could be enhanced.

#### Cons

- Response times for local distribution system outages and problems would increase as restoration work would have to be well coordinated with PG&E and each distribution pocket would have to be dealt with independent of the others.
- A non-integrated distribution system would be more difficult to monitor, control, and maintain than an integrated whole and reliability would likely suffer.

### Local Control

Local control refers to the perceived and actual ability of the customer to influence the policies and activities of the public agency and the ability of the governing body to more readily respond to local environmental and social needs. Local control allows self-regulation and the freedom to consider only constituent needs and sound business practices, not shareholders. The following are some considerations in regard to local control.

#### PG&E Owns Distribution

- The local agency would continue to have limited influence or control over issues such as distribution reliability, electric system aesthetics, siting and construction issues, line extension rules and fees, outage notification and repair, metering and meter reading, billing, customer care, and the total cost of electric utility service. Delivery and associated services typically comprise about 15% to 20% of the total cost of service. Distribution costs, rate designs, and special pricing packages or contracts would not necessarily meet the needs of local customers.
- Influence over conservation, energy efficiency, low-income benefits, and environmental concerns would be limited to CPUC and CEC regulatory forums. Customers would be paying for these services without a guarantee that funds are spent locally and without local input on how the funds are distributed.

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## **ELECTRIC ENERGY AND DISTRIBUTION SERVICE ISSUES AND OPTIONS**

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- As in the past, future surcharges could be applied by the CPUC to distribution customers.

### **SFPUC or New Municipal Agency Offers 100% of Distribution Service**

#### **Pros**

- Residents would have a stronger voice in setting policies for their electric distribution service and would help shape the future of distribution service for San Francisco.
- Local control would extend to: distribution reliability, electric system aesthetics, siting and construction issues, line extension rules and fees, outage notification and repair, metering and meter reading, billing, customer care, economic development and the total cost of electric utility service. The SF Muni would also be able to control retail distribution rates and pricing packages and make sure they met local needs. Financial reserves and plans could be developed that would help stabilize distribution rates over the long run.
- The SF Muni would have substantial control over conservation, energy efficiency, low-income benefits, and environmental concerns and could determine appropriate funding levels and programs.
- Constituents could influence decisions on capital expenditures, including policies on distributed generation and net metering.
- Options for distribution service that meet local needs could be offered.

### **SFPUC or New Municipal Agency Offers Spot Municipalization**

#### **Cons**

- Local control would only extend to those areas served by spot municipalization and not to the entire City, potentially creating conflicts of distribution services offered and customer expectations.
- Local control over distribution system reliability would be limited because PG&E would control distribution interconnections with the new utility and any problem on PG&E's distribution system would affect the new utility's distribution system. Any policies or distribution operations that affect the PG&E portion of the distribution system would need to be coordinated with PG&E and potentially the CPUC, limiting local control.
- Public purpose programs would be funded by only a subset of the City's residents and businesses, but would likely benefit the entire City. Careful planning would need to be followed if it was determined that program revenues would be spent on those who made the contributions.

# Governance

In conjunction with any of the services discussed above, governance of the new electric utility could be accomplished through one of two structures, a separate municipal agency with members elected by the public or expanding the authority and responsibilities of the current SFPUC. Any public governance structure will have a tendency toward less agility caused by legal requirements for open meetings and hearings, lack of a profit motive, and risk aversity. However, public governance of electric utilities also allows greater local control, removes shareholders and profit concerns from decision making, and is directly responsible to the consumers of electric services. The options for governance of a new electric utility for San Francisco are discussed further below.

## A New San Francisco Municipal Agency

If the new municipal utility Board was elected by the voters of San Francisco, it would be directly accountable to its constituency. The Board would be charged with managing the affairs of the new utility, whether it was structured to simply provide energy or whether its structure included distribution service. The Board would need to establish new operational policies, procedures, bylaws, hiring practices, legal counsel, financial administration, and union contracts.

Some pros and cons of creating a new agency to regulate electric services would be:

### Pros

- Constituents would likely have slightly stronger influence on rate-setting and rate structures if the utility is governed by a new agency.
- The new utility would offer local control at least over energy supply costs and possibly over distribution service.
- Policies governing new generation supply and risk mitigation would need to be considered.

### Cons

- A new Board would have to create all new systems for managing the utility. Regardless of whether the Agency offered distribution service only or distribution and energy services, the utility would need to develop a customer care, billing, and settlement system, an energy trading and risk management operation, an account management team, pricing services and packages, and would have to deal with many legal, regulatory, and public policy issues.
- A new government bureaucracy would need to be created and a stakeholder process managed. Staff members would need to be hired that have very specific expertise.
- The new utility would have to gain the trust of citizens and voters that it could meet their electrical needs reliably, efficiently, safely, and in a least cost way.

- Projected long run costs would have to be less than those projected for PG&E. If the retail cost of electricity was higher than PG&E, the voting public would not understand the need for a new municipal utility.
- The service options would have to be chosen carefully in order to minimize acquisition and customer maintenance costs. Specifically if the new Board were to control both energy and distribution service, the costs of severance from PG&E's existing service could be significant. Non-bypassable surcharges could apply whether the utility offers energy service only or has distribution service options as well.

### **Expanding the Role of the SFPUC**

Members of the SFPUC are appointed by the Mayor and are therefore accountable to the people of San Francisco through the Mayor. The SFPUC regulates retail water and wastewater services to the residents of San Francisco and regulates the production and sale of electric generation from the Hetch Hetchy hydroelectric project. Electricity produced by this project serves some municipal loads in the city. The SFPUC receives delivery services on transmission or distribution lines owned by PG&E through agreements with PG&E and CAISO. Additionally, the City owns transmission and distribution facilities, including 115-kV and 230-kV lines between its hydroelectric generation in the Sierras and Newark substation, numerous substations and transformers, and the distribution system serving SFO. The SFPUC regulates the structure of power sales to municipal customers, including price, term, quantity, and delivery points. The SFPUC manages a staff that performs the tasks of negotiating, contracting, pricing, marketing, accounting, billing, and settling current energy transactions. However, the main focus of the SFPUC today is water and wastewater services not electricity and the SFPUC would likely need to expand its staff and their capabilities in order to add a full range of electric services. The Board has established administrative rules and bylaws and existing agreements with organized labor. Some pros and cons of expanding the role of the SFPUC to regulate a broader range of retail electric services and customers are:

#### **Pros**

- Existing staff and administrative services could be leveraged to expand energy purchases and generation supply reasonable quickly.
- New staff would need to be added to provide distribution construction, repair, and maintenance if the SFPUC were to take on a distribution role. However, current staff that performs these services for existing electric transmission and distribution facilities could form a foundation and serve as the core group for expansion.
- Current water meter reading expenses, billing, settlement, customer care, legal, rate design, and other management functions could be reduced due to synergy with similar electric system requirements.

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- SFPUC staff has some experience in managing energy contracts and volatility. As load expands, the role of energy trading and contracting would become more risky and could require more oversight.

Cons

- The SFPUC is not directly accountable to constituents, but rather to the Mayor of San Francisco.
- The SFPUC staff has embedded policies, procedures, union contracts and work rules that would impose hurdles to agility and efficiency.
- The SFPUC would have to overcome a public image of being inefficient and bureaucratic.
- New generation supply would need to be purchased and appropriate risk mitigation measures would need to be considered.
- The SFPUC would need to quickly expand to integrate electricity service, particularly during any transition period. Even when a steady state is achieved, Board time spent on electricity is likely to be equal to, or require more time than currently spent on existing core businesses.

The following table summarizes the relationships between governance and service options.

Table 43  
Summary of Governance and Service Options

| Type of Service                                                               | Governance Type                                                                                                                                                                                                                                                                                                                                                                                                                                     |                                                                                                                                                                                                                                                                                                                                                                                               |
|-------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
|                                                                               | New Utility Board                                                                                                                                                                                                                                                                                                                                                                                                                                   | Expand SFPUC                                                                                                                                                                                                                                                                                                                                                                                  |
| Energy Only                                                                   | <ul style="list-style-type: none"><li>■ Board, staff, and administrative systems would need to be developed from scratch.</li><li>■ Offering "aggregation only" service limits local control to just energy.</li><li>■ No familiarity with energy trading and contracting.</li></ul>                                                                                                                                                                | <ul style="list-style-type: none"><li>■ Existing systems, administration, and staff could be leveraged.</li><li>■ Offering "aggregation only" service limits local control to just energy.</li><li>■ Familiarity with energy trading and contracting.</li><li>■ May be difficult to manage energy trading with water and wastewater services.</li></ul>                                       |
| Energy Service with Either Full Distribution Service or Spot Municipalization | <ul style="list-style-type: none"><li>■ Board, staff, and administrative systems would need to be developed from scratch.</li><li>■ Local control would cover energy and distribution service.</li><li>■ No experience with energy distribution.</li><li>■ Would need to gain the trust of constituents that it could operate the distribution system safely and reliably.</li><li>■ May be easier to offer distribution service options.</li></ul> | <ul style="list-style-type: none"><li>■ Existing systems, administration, and staff could be leveraged.</li><li>■ Local control would cover energy and distribution service.</li><li>■ More difficult to manage water and wastewater services with expanded energy role.</li><li>■ Perceived as more political and less likely to be responsive to constituents distribution needs.</li></ul> |

## Section 5

# CONSERVATION, ENERGY EFFICIENCY, AND RENEWABLE RESOURCES

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## Background and Introduction

Conservation and energy efficiency refer to the ability of the utility to encourage passive and active conservation measures by their customers. Passive conservation usually requires a simple change in behavior, like turning off lights and managing thermostat settings. Active conservation requires investment in conservation, like purchasing a new refrigerator, installing compact fluorescent bulbs, and adding insulation to walls or ceilings. The net effect of these changes is to reduce demand for both generation and transmission resources. Renewable generation (primarily wind and solar) and clean self-generation (mainly natural gas microturbines) can also help customers avoid the need for traditional utility resources and reduce the strain on congested utility systems without significantly impacting the environment.

Throughout the decade of the 1990s, utilities on the West Coast of the United States scaled back energy efficiency and conservation investments while cogeneration or renewable energy projects became less economic. The driver of these changes was low market energy prices, which served as the substitute for energy efficiency investments and new customer-specific generation resources. However, in 1996 California's electric restructuring law, AB 1890, mandated minimum funding levels for renewable technology investments and energy efficiency measures. In addition, the energy crisis of 2000-2001 brought extreme price spikes and volatility to energy markets that increased customer, utility, and legislative interest in these programs. Presently, the State of California has appropriated millions of dollars to be spent on energy efficiency and has created both the Flex Your Power campaign and the Governor's 20/20 program to encourage people not to waste electricity. The state has also funded major utility programs that encourage the use of renewable generation technologies and clean self-generation. AB 970 allocated California General Fund revenues to provide project subsidies that encourage solar, wind, fuel cell, and natural gas micro-turbine projects. With funding from this bill, PG&E implemented programs that target new installations of renewable generation over 30 kW. Under the auspices of the same bill, the CEC has a similar incentive program that provides support for projects with less than 30 kW of capacity. In addition, legislation requiring renewable resources to be part of energy portfolios and more lenient net metering laws are continuing to encourage further investment in clean self-generation and renewable technologies. While these investments and changes have occurred mainly to avoid expensive short term energy markets, supporters of energy conservation and renewable or clean self-generation also point to the following reasons to invest in new energy saving technology.

## Section 5

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- Improvements in energy efficiency and new renewable generation reduce the need for traditional generation and transmission resources.
- Passive conservation requires little investment and minor adjustments to customer lifestyles, and can cut electric demand and energy use significantly.
- All conservation reduces demand for electricity, which puts downward pressure on market prices.
- Efficient use of electricity saves natural resources and helps the environment.
- Active conservation reduces electric requirements now and in the future, while not reducing benefits to customers.
- Conservation programs in conjunction with other public purpose programs (low-income discounts) are symbiotic, and can be funded and administered jointly.
- New and improving technology along with increased production have made natural gas microturbines, fuel cells and photovoltaic arrays cheaper and more available.
- Distributed generation can support the local distribution grid and can significantly reduce customer demand on traditional electric systems.
- Issues of environmental justice are reduced when new generation and transmission can be avoided.

Energy efficiency and renewable energy funds are appropriated and collected as required by California law, Public Utilities Code Section 381-384, which provides funding through a surcharge on energy sales. The revenues collected through the surcharge are dispersed through IOUs, with regulation from the CPUC or through the CEC, which manages both its own programs and provides grants to both IOUs and municipal utilities. In addition to grants from the CEC, some municipal utilities also fund their own programs and self-regulate their own program design and effectiveness. Minimum funding levels and recovery mechanisms for energy efficiency and renewable generation investments were mandated by AB 1890 but were continued and enhanced through numerous new laws during 2001. Either the CEC or the CPUC provide oversight for the majority of new money dedicated to energy efficiency or renewable development. Program oversight by either of these regulatory authorities generally involves a project plan for spending the allocated dollars, a forecast of expected results and energy savings, and an evaluation of the program after it is implemented to ensure the program is achieving its goals. Both IOUs (regulated by the CPUC) and municipal utilities (self-regulated but may also report to the CEC) have developed rates and tariffs that provide rebates and other incentives for utility customers to conserve energy or to invest in renewable generation resources. Studies are usually performed to determine which programs are the most cost effective, given expected results. The following table demonstrates some of the programs that major Northern California utilities and the CEC have implemented.

## CONSERVATION, ENERGY EFFICIENCY, AND RENEWABLE RESOURCES

**Table 5-1**  
**Programs Implemented by the CEC and Northern California Utilities**

| Program Manager             | Program                                                                                                | Funding                                                                                      |
|-----------------------------|--------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------|
| SMUD                        | ■ Residential – Air conditioners, whole house fans, heat pumps, lighting                               | ■ \$50–\$500                                                                                 |
|                             | ■ Commercial – Cool Roof Program                                                                       | ■ \$0.20 per sq ft                                                                           |
| PG&E                        | ■ Residential – Programmable thermostats to heat pumps and furnaces                                    | ■ \$20–\$500                                                                                 |
|                             | ■ Commercial – Equipment rebates to self-generation projects                                           | ■ Varies (> \$50 million total funding)                                                      |
| Modesto Irrigation District | ■ Residential – From window film to central air conditioners                                           | ■ \$50–\$500                                                                                 |
|                             | ■ Commercial – Lighting, windows, air conditioning                                                     | ■ Varies                                                                                     |
| CEC                         | ■ Residential – Solar water heating, shade screens, renewable generation                               | ■ Water heating \$750, screens \$1 per sq ft, generation \$4.50 per watt (up to 50% of cost) |
|                             | ■ Commercial – Peak load reduction programs, lighting, building insulation, HVAC, renewable generation | ■ Load reduction \$20 million, Generation same as residential                                |

### San Francisco Energy Efficiency and Renewable Generation Programs

San Francisco has a reputation for promoting environmentally friendly technologies. Due to the recent energy crisis and rolling blackouts suffered by the City, energy efficiency and renewable generation options have received significant attention. The City has realized investments in these programs can help the City:

- Reduce the need for more investment in traditional transmission and generation infrastructure.
- Reduce congestion on key transmission pathways into the City, improving reliability.
- Reduce the use of inefficient and polluting Hunter's Point and Potrero power plants.
- Improve air and water quality.
- Reduce demand for short term power, which helps lower market prices.
- Mitigate environmental justice issues without sacrificing quality electric service.

The following projects have recently been implemented by the City to support these goals.

- The Mayor's Energy Conservation Account (MECA) was established in 2001 to finance energy efficiency measures in city buildings and facilities. The fund was established through state grants and low interest loans, which will be paid back

through energy savings from the investments. There are currently 15 energy efficiency projects that are being financed with the funds, which should save the City about 70 million kWh per year. The projects presently involve lighting retrofits, on-site electricity generation, HVAC work, and new energy efficient refrigerators.

- The San Francisco Department of Environment began administering a Resource Efficient Buildings (REB) program in 1999. This program helps ensure buildings are designed, constructed, renovated and demolished in an environmentally sustainable way. The program encourages this goal by providing Green Building Design Training for all city architects, engineers and project managers, demonstrating innovative green building design and construction practices through implementation of 10 city pilot projects, and by evaluating the performance of environmentally friendly construction practices at the pilot projects.
- On November 6, 2001, San Francisco passed two new propositions to support solar, wind, and energy efficiency projects through selling \$100 million in revenue bonds, to be paid back through energy savings achieved by the programs. The propositions provide financing for about 10 to 12 megawatts of solar power and about 30 megawatts of wind generation. \$50 million will be spent to install solar arrays on schools and other city-owned facilities and \$30 million will be spent to place wind turbines on city and county-owned properties. The remainder will be spent on energy conservation and costs associated with the projects and issuing the bonds. Through these generation capacity additions, renewable resources are projected to meet 5% of San Francisco's peak electricity load, providing clean and reliable power for San Francisco's energy future.

## Key Considerations of Conservation, Energy Efficiency, and Renewable Resources

### Rates and Pricing

#### PG&E Status Quo

PG&E currently collects funds for conservation and renewable resources support through a usage fee added to distribution rates. The fee is currently \$0.00432 per kWh for PG&E residential customers. Program revenue is allocated to four public benefit program categories and spent on projects on a case by case basis with regulation from the CPUC. In addition to the program funding from distribution rates, new laws passed in 2000 and 2001 have provided PG&E additional money (primarily from California's General Fund) to fund more rebate and incentive programs. These programs are also regulated by the CPUC and have fixed sunset dates as long as all the program money has been spent. PG&E has no incentive to ensure that local contributions to energy efficiency and renewable resource programs are spent locally.

### **SFPUC or New Municipal Agency**

Ultimate program funding and decisions on which programs to support would be governed by the SF Muni if it enters the distribution business. However, if it chooses to enter only the energy supply business, any new funding would be in addition to PG&E's \$0.00432 per kWh. Therefore, if the funding mechanism were based on a percentage of total revenue and the SF Muni offered energy-only service and not distribution service, than total revenues would likely be low to avoid excessive ratepayer charges and there would be less money available for SF Muni-controlled energy efficiency and renewable generation programs. For spot market customers, the SF Muni could control the surcharge to either match the current surcharge paid by customers of PG&E or the revenue that is currently collected by PG&E.

Conservation and energy efficiency programs can also seem quite expensive, especially when market energy prices are low. A cost/benefit analysis and a life-cycle analysis should be performed to determine which programs should be implemented and which should be avoided.

### **Reliability**

#### **PG&E Status Quo**

PG&E does not typically invest in energy efficiency, distributed generation or renewable technologies to improve distribution system reliability. As long as the CPUC continues to allow PG&E to earn reasonable returns on invested distribution plant and distribution revenue requirements are primarily recovered through usage based rates, PG&E will have an incentive to continue to expand its distribution system and maximize usage on that system.

#### **SFPUC or New Municipal Agency**

Conservation and energy efficiency reduces the need for additional distribution, transmission, and generation resources. Short run conservation measures (more passive conservation) will reduce the stress on congested distribution and transmission lines and will reduce reliance on the purchase of short term market energy, which will help balance short run market supply and demand. Long run conservation measures (more active conservation) are more likely to reduce long run demand and energy, such that additional supply and delivery resources can be completely avoided. The effects of both short run and long run conservation should help improve delivery system reliability and the need for rolling blackouts as a system stability tool. The new utility could study the effect energy efficiency and renewable technology investments have on reliability and offer only those programs that provide the greatest value in terms of combined energy efficiency and enhanced distribution system reliability.

### Local Control

#### PG&E Status Quo

PG&E is mandated by California law to provide energy efficiency funding. The revenues for the programs are based on how much energy consumers use, while the expenditures of program funds are based on individual project needs and requirements. There is no guarantee that funds contributed locally are spent on local energy efficiency projects. The City has very limited influence over the size of budgets for energy efficiency and renewable technologies and what programs ought to be offered to local businesses and residents. PG&E has little choice on how to spend allocated funds, as program funding is often dictated by legislation and regulated by the CPUC.

#### SFPUC or New Municipal Agency

If a SF Muni offered electric service and created a conservation and energy efficiency funding mechanism, 100% of funds collected locally could be invested locally. A local regulatory authority, accountable to local constituents, would make final decisions regarding the level of conservation funding and the expenditures of the funds. The following are some other considerations regarding local control of energy efficiency and renewable funding.

##### Pros

- Current program funding is about 2.85% of gross revenues. The SF Muni would have control over the level of funding for these programs and could adjust the level according to local needs and interest.
- The SF Muni could control which programs get support and which do not. Program choices could include low-income assistance, conservation and demand-side management, renewable technology, or research and development. The SF Muni would have the flexibility to decide which programs best meet local needs and fund only those programs.
- SF Muni-managed energy efficiency and renewable generation could significantly impact the feasibility of new generation and transmission projects, providing local control to new resource decisions.
- Environmental justice issues would be reduced without sacrificing legitimate electricity needs.

##### Cons

- If the SF Muni only provides energy service and not distribution service, consumers may pay more than other PG&E customers are paying for energy efficiency and renewable programs.
- If the SF Muni gets involved in spot municipalization, issues of fairness may arise as only certain SF Muni customers would be funding SF Muni-managed energy

## **CONSERVATION, ENERGY EFFICIENCY, AND RENEWABLE RESOURCES**

efficiency and renewable programs but program expenditures may benefit everyone.

## Appendix C

### LEGAL DISCUSSION OF GOVERNANCE

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**I. Role of San Francisco Local Agency Formation Commission:**

The San Francisco LAFCo was formed in August of 2000 as a result of an initiative petition to create a municipal utility district for the City and County of San Francisco and the City of Brisbane. Although this measure was narrowly defeated at the polls, the Commission determined that public hearings should be held to gather information from energy experts regarding the current utility service needs of San Francisco and the various options that may be available to increase service reliability, efficiency and cost effectiveness. These hearings are consistent with LAFCo's primary purpose which is to review public service needs, including utility service, and to determine whether new government entities should be created or changes in existing governments should be made to address the needs of its citizens.

From February 2002 until April 2002, the San Francisco LAFCo conducted a series of public hearings and representatives from the following public entities and private organizations provided presentations:

- San Francisco Public Utilities Commission (SFPUC)
- State of California Consumer Power and Conservation Authority  
(California Power Authority)
- California Public Utilities Commission (CPUC)
- P G & E
- Sacramento Municipal Utility District (SMUD)
- Representative who managed utility department for the Cities of Anaheim, Palo Alto, Austin, Texas and Pasadena

- City of Roseville
- City of San Jose
- Onsite Energy Group specializing in cogeneration development and operation
- The Utilities Reform Network (T.U.R.N.)
- Northern California Power Agency

The information provided through the hearings is available through the LAFCo Executive Officer. At the conclusion of the hearings, the Commission determined that a study should be prepared to provide the public with information regarding the utility needs of San Francisco. A critical part of this analysis is an understanding of the various ways in which government can provide utility services to its citizens.

## **II. San Francisco Public Utilities Commission (SFPUC):**

### **A. Authority to Provide Electric Utilities:**

Currently, SFPUC is responsible for overseeing “the construction, management, supervision, maintenance, extension, operation, use and control” of all the City’s energy supplies and utilities. (1996 San Francisco City and County Charter (San Francisco Charter) § 4.112) SFPUC is authorized to contract for the provision of “heat, light and power for municipal purposes.” (San Francisco Administrative Code § 2A.130)

### **B. Governance:**

Created under the San Francisco Charter, SFPUC is a department of the executive branch of San Francisco. (San Francisco Charter § 4.112) SFPUC is governed by five (5) Commissioners, appointed for four-year terms by the Mayor subject to the veto power

of the Board of Supervisors. (San Francisco Charter §§ 3.100, 4.112) The Mayor is responsible for generally administering and overseeing each department or unit of the executive branch, including SFPUC, and has the power to sit but not vote on all matters. (Charter § 3.100(1)(9)) A General Manager, appointed by the Commission, monitors daily operations as the chief administrative officer of SFPUC.

### **C. Operations:**

SFPUC is operationally divided into the General Manager's Office, Hetch Hetchy Water and Power ("HHWP") and the Utilities Engineering Bureau. HHWP, a support bureau of SFPUC, operates and maintains three hydroelectric powerhouses in the vicinity of Yosemite National Park. HHWP's transmission lines deliver the electricity generated in the mountains to Turlock and Modesto Irrigation Districts and to PG&E in the Bay Area for distribution.

HHWP provides electricity for all of San Francisco's municipal functions, including San Francisco Municipal Railway and San Francisco International Airport and sells excess electricity at cost to Modesto and Turlock Irrigation Districts.<sup>1</sup> Any additional power is sold to public entities and private business, but not to the general public.

### **D. Acquisition of Utilities:**

San Francisco has the authority to acquire and own public utilities "when public interest and necessity demand." (San Francisco Charter § 16.101) The Board of Supervisors must obtain a report from the SFPUC whenever the Board determines that

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<sup>1</sup> The Raker Act of 1913 granted rights-of-way through Yosemite National Park and Stanislaus National Forest to San Francisco for the production of hydroelectric power through the Hetch Hetchy system. Under the Raker Act, San Francisco is required to sell electricity it produces in excess of its own municipal needs to Modesto and Turlock Irrigation Districts at cost.

“public interest or necessity demands the acquisition, construction or completion of any public utility” by San Francisco or the public petitions the Board to acquire any public utility. (San Francisco Charter § 16.101) SFPUC is responsible for valuing the acquisition of a public utility. (San Francisco Administrative Code § 2A.130)

#### **E. Use of Operational Revenue:**

HHWP’s operational revenue is allocated for expenses related to operating, repairing and replacing existing facilities, bond payment, “extensions and improvements,” and a surplus fund for each utility. Surplus funds are transferred to the General Fund of the City and County by the Board of Supervisors. (Charter § 16.103)

#### **F. Restrictions on Bonding:**

The Board of Supervisors may fund construction and acquisition projects by providing for the issuance of revenue bonds or general obligation bonds in compliance with state and local law. (San Francisco Charter §§ 9.106, 16.101) General obligation bond indebtedness may not exceed “three percent of the assessed value of all taxable real and personal property, located within the City and County.” (Charter § 9.106) Revenue bonds require majority voter approval unless they are issued for the purpose of reconstructing or replacing current energy facilities and are authorized by resolution of the Board of Supervisors adopted by a three-fourths vote; or to finance certain projects for conservation and renewable energy facilities or equipment. (Charter § 9.107)

### **III. Forms of Municipal Utility Service:**

#### **A. Municipal Utilities:**

##### **(i) Authority:**

A city is legally authorized to furnish electric power to its inhabitants. Under Section 9 of Article 11 of the California Constitution, a municipal corporation may “establish, purchase and operate public works to furnish its inhabitants with . . . power.” The authority to provide municipal utility service is broad. The municipality may determine that it will provide a complete utility service or only certain portions of service. Although a municipality may grant a utility franchise to an investor utility such as P G & E, the municipality still retains the power to acquire back the utility franchise by purchase or condemnation. The power to operate a municipal utility is flexible. According to Public Utilities Code section 10004:

“[A] municipal corporation may acquire, own, control, sell, or exchange lands, easements, licenses, and rights of every nature within or without its corporate limits, and may operate a public utility within or without the corporate limits when necessary to supply the municipality, or its inhabitants or any portion thereof, with the service desired.”

A municipal corporation may also “sell, lease, or distribute” surplus power outside of its territory. (Public Utilities Code section 10005)

**(ii) Formation:**

Cities have the power to provide electric utilities by creating new departments within themselves. A city may create its own utilities department by amending its charter or its municipal code through adoption of an ordinance.

**(iii) Governance:**

The City’s legislative body or an independent board may govern the utilities department. An independent board may be appointed by the City’s legislative body or mayor and may be representative of the general public or a class such as industry, consumer groups or financial experts. The independent board may also be elected by general or district vote. Mayoral appointment is typically subject to the legislative body’s

approval.<sup>2</sup> Although legislative bodies govern most public utilities, independent boards govern the majority of those that serve over 50,000 customers.<sup>3</sup>

For example, the City of Roseville's utility department is governed by the City Council. A five (5) member advisory commission appointed by the Council provides recommendations to the City Council. Utility funds are kept separate from the general fund of the City.

The City of Los Angeles created the Los Angeles Department of Water and Power ("LADWP") under the City Charter as a Proprietary Department of the City of Los Angeles. (Charter of the City of Los Angeles § 600) LADWP is the largest municipal utility in the world. It is governed by a five (5) member Board of Water and Power Commissioners, appointed by the Mayor, subject to City Council approval. (Charter of the City of Los Angeles §§ 502, 670, 675)

The City of Pasadena created Pasadena Water and Power ("PWP") by ordinance under the Pasadena Charter as a department of the City. (Charter of the City of Pasadena Title 2, Chapter 2.305.010) PWP provides electricity to 57,000 customers within the City. PWP is directed by a General Manager appointed by the City Manager. Pasadena's City Manager is charged with general administration of the utilities department subject to City Council oversight. (Charter of the City of Pasadena Title 2, Chapters 2.255.020, 2.305.010)

The American Public Power Association asked publicly owned electric utilities to identify the governing body or individual within their system that controls key decisions such as rate-setting, budget and bonding issues, condemnation and personnel matters.

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<sup>2</sup> American Public Power Association, *2001 Governance Survey*, July 2001.

<sup>3</sup> *Id.*

For utilities governed by legislative bodies, the study found that the legislative body usually controls most of the actions that were surveyed. In some cases, individual officials such as a city treasurer, utility general manager or city manager decide investment and personnel decisions. On the other hand, independently governed utilities reported that their boards typically make most of the surveyed decisions such as determining salaries, approving budgets, investing and purchasing power. However, boards are less likely to have final approval over issuing bonds and exercising eminent domain powers.<sup>4</sup>

**B. Joint Power Authority:**

A municipality may enter into a joint powers agreement with another public entity to provide certain municipal utility services and exercise certain powers. Joint powers agreements are authorized under state law and merely require the consent of the public agencies involved.

**(i) Formation:**

A joint powers authority may be created by agreement between two or more public agencies. The joint powers authority created is a separate legal entity from the creating public agencies. It has the powers designated in the agreement, which must be a power common to the creating agencies.

**(ii) Governance:**

A joint powers authority is governed by an appointed body. The terms and nature of the appointment is set forth in the joint powers agreement

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<sup>4</sup> *Id.*

#### **IV. Municipal Utility Districts:**

##### **A. Authority:**

Municipal utility districts have broad power to provide electricity. A municipal utility district may "acquire, construct, own, operate, control, or use, within or without . . . the district, works . . . for supplying the inhabitants of the district and public agencies therein" with "power" and "may do all things necessary or convenient to the full exercise of" such powers. (Public Utilities Code section 12801)

##### **B. Formation:**

Municipal utility districts are formed by two or more "public agencies," or a public agency and unincorporated territory, acting together. (Public Utilities Code section 11561) The term "public agency" includes a "city, county water district, county sanitation district, or sanitary district." (Public Utilities Code section 11504) The City and County of San Francisco may not form a municipal utility district under current law without joining with another public agency outside the City/County boundaries.

The formation process is initiated by resolutions of at least half of the public agencies involved or by petition. (Public Utilities Code §§ 11581, 11611) The board of supervisors of the county with the most voters inside the proposed boundary of the district receives the resolutions or petition. (Public Utilities Code §§ 11583, 11611) In order to form a municipal utility district, the resolution or petition must be presented to the local agency formation commission of the county and proceedings conducted in accordance with the Cortese Knox Hertzberg Local Government Reorganization Act of 2000. In addition, a report of the California Public Utilities Commission may be required. Finally, the creation of a municipal utility district would be subject to the

California Environmental Quality Act. Due to these requirements, the process to establish a municipal utility district can be lengthy.

**C. Governance:**

An independently elected board of directors governs a municipal utility district. The voters, divided into five wards within the proposed district boundary, decide the issue of formation and select one director from each ward to sit on the board of directors. (Public Utilities Code §§ 11641, 11642, 11646) The board of directors is a legislative body that regulates the utilities within the district. (Public Utilities Code §§ 11883, 11885)

**V. City Energy Efficiency and Conservation Programs Provided in Addition to Private Investor Utility Service:**

Instead of forming a municipal utility or a municipal utility district, some cities have elected to retain utility service from existing investor-owned utilities such as P G & E and complement these services with City programs or policies that promote energy efficiency and conservation. The City adopts programs that encourage and facilitate new building construction and rehabilitation with energy efficient code and zoning requirements. The programs promote the use of renewable energy and typically involve the adoption of building design and construction features that reduce energy operation and maintenance costs. An example of this type of City commitment is the City of San Jose's Green Building policy. The City has adopted the "Leadership in Energy and Environmental Design" (LEED) rating system and requires that new construction and retrofit of buildings meet specific criteria. The City of Santa Monica has developed its

own rating system. The City of Portland has a “Green Building Action Plan” and “green building staff” are allocated throughout the various City departments, including the public works, planning, utility, and building departments.

**(i) Authority:**

The City and County of San Francisco currently has the authority through its building code and zoning powers to implement energy efficient programs.

**(ii) Formation:**

The City and County of San Francisco already has a building department and public works department that typically administers such programs. No additional governmental structure is required.

**(iii) Governance:**

The legislative body of the permitting public entity governs these programs, which would be the City and County of San Francisco. In addition most public entities have created an advisory group appointed by the legislative body to make recommendations to the legislative body regarding policies and new programs.

**VI. Findings:**

Based upon the information provided through the hearing process and reviewing the different governance structures, the following findings can be made:

1. The City and County of San Francisco has an existing utility department in the SF PUC with experienced staff and established programs.
2. The SF PUC has proposed an energy plan which sets forth short term and long-term utility policies and programs. A copy of the plan is attached to this report.

3. Current language in the San Francisco charter limits the SF PUC ability to respond to a changing energy market. The Commission should consider charter amendments to remove restrictions on the SF PUC to allow greater flexibility and local control for energy needs.
4. Surplus funds generated by the SF PUC are currently transferred to the City general fund pursuant to the charter terms. The Commission should consider recommending a charter amendment to limit the transfer of surplus funds to the general fund to allow greater flexibility for utility financing and programs.
5. San Francisco has the necessary authority and charter provisions for the operation of a municipal utility. The Commission should consider whether the current appointment structure of the governing body of the SF PUC is adequate in the event additional powers are recommended. The issue of accountability, local control and governance should be addressed in terms of the specific powers granted to the governing body.
6. The City and County of San Francisco cannot currently form a municipal utility district within its boundaries. State law would have to be amended to allow such a district to be formed. Without such a state law amendment, the City and County would have to join with another public entity outside of the City and County of San Francisco in order to form such a district. Given the unique nature of the energy needs of the City and County of San Francisco (including supply, transmission and generation) it is not certain whether such a district is advisable. This is particularly true given the fact that the City and County of San Francisco

has an established utility department and has the necessary powers to provide utility service if advisable.

7. The Commission should that recommend that the City and County of San Francisco review and adopt energy efficiency programs, building codes and zoning ordinances that promote energy conservation and energy efficiency.

*[Note: The following information regarding condemnation may be inserted in a different section of the report.]*

### **Extraterritorial Condemnation:**

California Code of Civil Procedure section 1240.125 authorizes a "local public entity" to acquire extraterritorial property by eminent domain for "electric supply purposes" if the public entity is otherwise authorized to acquire property by eminent domain for such purposes. Section 1240.125 states:

"Except as otherwise expressly provided by statute and subject to any limitations imposed by statute, a local public entity may acquire property by eminent domain outside its territorial limits for water, gas, or electric supply purposes or for airports, drainage or sewer purposes if it is authorized to acquire property by eminent domain for the purposes for which the property is to be acquired."

The term "local public entity" is defined to include "any public entity other than the state." (Code of Civil Procedure section 1235.150)

Cities are authorized to "acquire by eminent domain any property necessary to carry out any of its powers or functions." (Government Code section 37350.5) Similarly, a municipal utility district formed under the Municipal Utility District Act, "may exercise the right of eminent domain to take any property necessary or convenient to the exercise of the powers granted" in the Act. (Public Utilities Code section 12703) A municipal utility district may condemn property "within or without the district necessary to the full or convenient exercise of its powers." (Public Utilities Code section 12771)

## Appendix D

### GLOSSARY OF TERMS

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**Aggregator** -- An entity that puts customers into a buying group for the purchase of a commodity service. The vertically integrated investor owned utility, municipal utilities and rural electric cooperatives perform this function in today's power market. Other entities such as buyer cooperatives or brokers could perform this function in a restructured power market.

**Ancillary Services** -- Services that the Independent System Operator may develop, in cooperation with market participants, to ensure reliability and to support the transmission of energy from generation sites to customer loads. Such services may include: regulation, spinning reserve, non-spinning reserve, replacement reserve, voltage support, and black start.

**Bilateral Contract** -- A two-party agreement for the purchase and sale of energy products or services.

**Blackout** -- A power loss affecting many electricity consumers over a large geographical area for a significant period of time.

**California Energy Commission** -- The state agency established by the Warren-Alquist State Energy Resources Conservation and Development Act of 1974 (Public Resources Code, Sections 25000 et seq.) responsible for:

- Forecasting future statewide energy needs
- Licensing power plants
- Promoting energy conservation and efficiency measures
- Developing renewable and alternative energy resources

**California Independent System Operator (CAISO)** -- The CAISO is the FERC regulated control area operator of most of the transmission assets in California. Its responsibilities include providing non-discriminatory access to the grid, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services. The ISO has no affiliation with any market participant.

**California Public Utilities Commission (CPUC)** -- A state agency created by constitutional amendment in 1911 to regulate the rates and services of more than 1,500 privately owned utilities and 20,000 transportation companies. The CPUC is an administrative agency that exercises both legislative and judicial powers; its decisions and orders may be appealed only to the California Supreme Court. The major duties of the CPUC are to:

- Regulate privately owned utilities from customer service to construction activities
- Ensure adequate utility service at rates that are just and reasonable to both customers and shareholders

- Evaluate infrastructure developments and issue Certificates of Public Convenience and Necessity (CPCN)
- Forecast electric and natural gas resource needs
- Analyze and plan energy supply and resources

**Capacity** -- The maximum amount of electricity that a generating unit, power plant or transmission or distribution line can deliver under specified conditions. Capacity is measured in megawatts.

**Cogenerator** -- Cogenerators use the waste heat created by one process, for example during manufacturing, to produce steam which is used, in turn, to spin a turbine and generate electricity. Cogenerators may also be QFs.

**Competition Transition Charge (CTC)** -- A "nonbypassable" charge generally placed on distribution services to recover utility costs incurred as a result of restructuring (stranded costs - usually associated with generation facilities and services) and not recoverable in other ways.

**Congestion** -- A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules simultaneously.

**Congestion Management** -- Alleviation of congestion by the ISO.

**Conservation** -- Activities that reduce the amount of energy being consumed while accomplishing the same amount of work. This may involve installing new equipment, modifying equipment, or simply changing behavior patterns.

**Control Area** -- An electrical region that regulates its generation in order to balance load and maintain planned interchange schedules with other control areas and assists in controlling the frequency of the interconnected system in accordance with WECC and NERC criteria

**Demand** -- The rate expressed in kilowatts, or megawatts, at which electric energy is delivered by a system at a given instant or averaged over a designated interval of time

**Direct Access** -- The ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than through a local distribution utility.

**Distribution** -- The delivery of electricity to the retail customer's home or business through low voltage electric lines.

**Distributed Generation** -- Small capacity electric generators meant to offset a portion of, or all of, the electrical requirements of a single customer or group of customers. Distributed generation can reduce the need for additional, or upgraded distribution, transmission or large scale, centrally located generation facilities.

**Energy Efficiency** -- Using less energy/electricity to perform the same function.

**Energy** -- This is broadly defined as the capability of doing work. In the electric power industry, energy is more narrowly defined as electricity supplied over time, express in kilowatt-hours.

**Energy Services Provider (ESPs)** – ESPs are Sellers of energy and coordinators (as well as possibly providers) of other essential elements of energy service necessary for customers to use energy. They are made up of power aggregators, generators, utilities, municipalities, power marketers and brokers, who match buyers and sellers, tailor both physical and financial instruments to suit the needs of particular customers, and aggregate small customer loads to form buying groups or cooperatives that give them additional bargaining power.

**Federal Energy Regulatory Commission (FERC)** -- An independent regulatory commission within the U.S. Department of Energy that has authority to:

- Regulate energy producers that sell or transport fuels for resale in interstate commerce
- Set oil and gas pipeline transportation rates and to set the value of oil and gas pipelines for ratemaking purposes
- Regulate wholesale electric rates and hydroelectric plant licenses.

**Grid Management Charge** -- An approved FERC tariff which recovers the CAISO's on-going operating and management costs.

**Investor-Owned Utilities (IOUs)** -- A private company that provides a utility, such as water, natural gas or electricity, to a specific service area. The investor-owned utility is regulated by the California Public Utilities Commission. In California the investor owned utilities supplying energy are:

- Canadian Pacific National Corporation
- Pacific Gas and Electric Company
- Pacific Power and Light Company
- San Diego Gas & Electric
- Sierra Pacific Power Company
- Southern California Edison Company
- Southern California Gas Company (The Gas Company)
- Southwest Gas Corporation

**Locational Marginal Price** -- The price at which supply equals demand at a specified location on the transmission system. All demand that is prepared to pay at least this price

at the specified location has been satisfied and all supply which is prepared to operate at or below this price in the specified location has been purchased.

**Municipalization** -- The process by which a municipal entity assumes responsibility for supplying utility service to its constituents. In supplying electricity, the municipality may generate and distribute the power or purchase wholesale power from other generators and distribute it.

**Municipal Utility** -- A provider of utility services owned and operated by a municipal government.

**Obligation To Serve** -- The obligation of a utility to provide electric service to any customer who seeks that service, and is willing to pay the rates set for that service. Traditionally, utilities have assumed the obligation to serve in return for an exclusive monopoly franchise.

**Participating Transmission Owner** -- An entity that owns transmission facilities and has turned over the operation control of those facilities to the CAISO.

**Regional Transmission Organization (RTO)** -- An organization that would coordinate the operation and dispatch of the transmission system over most likely a multi-state jurisdiction. The RTO would ensure open, non-discriminatory access to transmission, organize ancillary service markets, provide market surveillance, and manage congestion.

**Reliability** -- Electric system reliability has two components-- adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

**Renewable Resources** -- Renewable energy resources are naturally replenishable resources that can be used for electric generation. Renewable energy resources include: biomass, hydroelectric, geothermal, solar and wind. In the future they may also include the use of ocean thermal, wave, and tidal action technologies.

**Tariff** -- A document, approved by the responsible regulatory agency, listing the terms and conditions, including a schedule of prices, under which utility services will be provided.

**Transmission Access Charge** -- A charge paid by all market participants withdrawing energy from the ISO controlled grid. The access charge supports recovery of a utility's transmission revenue requirement.

**Transmission Owner** -- An entity that owns transmission facilities or has firm contractual right to use transmission facilities.

**Unbundling** -- Disaggregating electric utility service into its basic components and offering each component separately for sale with separate rates for each component. For example, generation, transmission and distribution could be unbundled and offered as discrete services.

**Wheeling** -- Using a utility's lines to transport power from one neighboring system to another.

**The Western Electric Coordinating Council (WECC)** -- A voluntary industry association created to enhance reliability among western utilities.

**Wholesale Power Market** -- The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.





